National Energy Board

Natural Gas Market Assessment

October 1988

National Energy Board

Natural Gas Market Assessment

October 1988

Cat. No. NE 23-27/1988 E
ISBN 0-662-16600-0

This report is published separately in both official languages.

Ce rapport est publié séparément dans les deux langues officielles.

Copies are available on request from:

Regulatory Support Office
National Energy Board
473 Albert Street
Ottawa, Canada
K1A 0E5
(613) 998-7204

Exemplaires disponibles auprès du:

Bureau du soutien de la réglementation
Office national de l'énergie
473, rue Albert
Ottawa (Canada)
K1A 0E5
(613) 998-7204

Printed in Canada

Imprimé au Canada

Foreword

In a decision dated July 1987, the National Energy Board adopted a "Market-Based Procedure" to ensure that natural gas licensed for export is surplus to reasonably foreseeable Canadian requirements. As part of this new procedure, the Board is committed to monitoring the Canadian natural gas market to be alert to any difficulties for Canadians in adjusting to changes in natural gas supply and demand.

The Board stated that it would continue to issue it's biennial report on the long term prospects for Canadian energy supply and demand. In addition, it would also periodically report on the current functioning of the natural gas market, including the short term prospects for the supply of and demand for Canadian natural gas.

This initial short term report, titled Natural Gas Market Assessment, has two broad objectives. First, it provides a review of the functioning of the Canadian natural gas market and an assessment of the market's performance in satisfying Canadian needs since the introduction of freely negotiated prices. Second, it provides an assessment of the short term outlook for the supply of and demand for Canadian natural gas, including an assessment of available pipeline capacity.

This report differs from the Board's biennial study, Canadian Energy Supply and Demand, in that it focuses entirely and in greater detail on natural gas, and provides a near-term analysis instead of a long-term projection.

An "executive summary" is not provided with this report. For those who desire a quick summary, we suggest reading the Introduction (Chapter 1) and the Conclusion (Chapter 6). Additional summary detail may be obtained by reading the summary assessments at the end of chapters 3, 4 and 5.

This report was prepared by Board staff. All interpretations, conclusions and forecasts are those of Board staff and are made without prejudice to future Board decisions on export and facilities applications or any other matters that may come before the Board.

Table of Contents

Chapter 1
Introduction 1

Chapter 2
Background to the 1985 Natural Gas Agreement 3

Chapter 3
The Structure and Functioning of the Canadian Natural Gas Market 11

Chapter 4
Canadian Gas Supply, Demand and Prices:
Short-Term Assessment 36

Chapter 5
Pipeline Capacity for Domestic and Export Markets 55

Chapter 6
Summary and Conclusions 64

Appendix A
Regulation of the Canadian Natural Gas Industry 67

Appendix B
Major U.S. Pipelines Providing Open Access Transportation 73

Appendix C
Glossary of Terms 74

Appendix D
Additional Footnotes to Figures 78

Chapter 1

Introduction

On 31 October 1985, the governments of Canada, British Columbia, Alberta and Saskatchewan signed an Agreement on Natural Gas Markets and Prices with the intent of fostering the development of a market-oriented pricing regime in the domestic gas market. This was to be achieved by allowing gas consumers to enter directly into gas purchase contracts with producers at freely negotiated prices (direct sales). The Agreement also envisaged enhanced supply access for Canadian gas users and enhanced market access for Canadian gas producers, while at the same time ensuring that reasonably foreseeable Canadian gas requirements would be protected.

Since the implementation of the Agreement on 1 November 1985, the National Energy Board (the Board) has twice reviewed and modified its gas surplus determination procedures. In its most recent decision, the Board noted that current energy policy was based on the premise that the marketplace should determine the supply, demand and price of natural gas. In these circumstances, the Board decided that its surplus determination procedures should be consistent with market-determined pricing.

Accordingly, the Board abandoned a formula approach and decided to license long term volumes of natural gas exports from Canada through a combined export hearing and monitoring process. This process is termed the "market-based procedure".

There are three components to the public hearings part of the market-based procedure:[1]

1) Complaints Procedure - the Board will consider complaints that Canadian users cannot obtain additional supplies of gas on terms and conditions, including price, similar to those in the export proposal. If the Board finds merit in a complaint it can either deny the application or defer issuing a final decision until an opportunity has been given for the situation to be rectified.

2) Export Impact Assessment - the Board will require applicants for export licences to file an impact assessment which will aid the Board in determining whether a proposed export would be likely to cause Canadians difficulty in meeting their energy requirements at fair market prices.

3) Public Interest Determination - the Board will continue, as required by Section 83 of the NEB Act, to have regard to all other factors it considers relevant in determining whether proposed exports are in the national public interest.[2]

The monitoring process consists of two parts. First, Board staff will continue to publish, about every two years, a supply and demand report which will examine the long term outlook for Canadian energy needs and supplies. This report will provide both the Board and the public with a reference viewpoint on the long term prospects for Canadian gas supply, demand and prices.[3]

1. For a detailed description of the Board's current surplus determination procedures, see Chapter Four of the Reasons for Decision in the Matter of Review of Natural Gas Surplus Determination Procedures, July 1987.
2. Adapted from NEB Press Release, "NEB Adopts New Natural Gas Surplus Determination Procedure", 9 September 1987.
3. The Board's most recent long term supply/demand assessment was released on 7 December 1988.

Second, from time to time Board staff will publish a short term assessment of the Canadian natural gas market. This is the first of these reports.

This initial report has three purposes.

1) One is to provide an assessment of the structure and functioning of the Canadian natural gas market since the introduction of market sensitive pricing. In abandoning a formula approach to its surplus determination procedures, the Board determined that Canadians should be able to satisfy their gas needs through private contractual arrangements. However, given that Canada had had virtually no experience with direct sales in the natural gas market, some concern had been voiced about the adequacy of market arrangements to protect Canadian needs. Therefore, the Board judged it appropriate that it monitor the functioning of the market and periodically report upon its findings.

2) A second purpose is to provide a description of the commercial and regulatory arrangements which currently govern the terms and conditions on which natural gas moves from the wellhead to the consumer. The changes in the industry over the last three years have been sufficiently profound to merit such an overview at this time.

3) The third purpose of this report is to provide a short term outlook for the domestic supply, demand and price of natural gas. This outlook should provide readers with a reference viewpoint as to likely near term market developments.

Organization of Report

Chapter 2 provides a brief review of the historical background that led to the implementation of the 1985 Gas Agreement. Readers familiar with this background may wish to proceed directly to Chapter 3.

Chapter 3 addresses the first two objectives of the report. It provides a review of the structure and functioning of the Canadian natural gas market, focussing on the last two years, the period during which direct sales of gas have become more generally available. The approach taken is to review the functioning of the market from the wellhead to the burner tip. The chapter concludes with an assessment of the functioning of the Canadian domestic market.

Chapters 4 and 5 address the third objective of this report. Chapter 4 provides both a review and a short term outlook for natural gas supply, demand and prices in the Canadian market. The approach taken is to separately examine domestic and export gas demand, followed by an assessment of productive capacity. The chapter concludes with an assessment of the outlook for the supply/demand balance in the domestic market in 1989.

Chapter 5 provides an assessment of available pipeline capacity against forecast throughputs for 1989.

The report's key findings are summarized in Chapter 6.

In addition, Appendix A provides a summary of the current status of the regulation of natural gas in Canada

Chapter 2

Background to the 1985 Natural Gas Agreement

Most of the natural gas consumed in Canada is produced in the three western provinces of British Columbia, Alberta and Saskatchewan. British Columbia's gas production is gathered and transported to both provincial and export customers through the facilities of Westcoast Energy Inc. (Westcoast).[1] Alberta's gas is gathered and transported to provincial, interprovincial and export customers on the system of Nova, an Alberta Corporation (NOVA). Saskatchewan's production is gathered and transported to provincial, interprovincial and export customers through the facilities of TransGas Corporation (TransGas).[2] Alberta and Saskatchewan gas is transported to both eastern Canadian and export markets through the facilities of the TransCanada PipeLines Limited (TCPL) system. British Columbia's gas fields are not yet connected to the NOVA system and production from these fields cannot be delivered to eastern Canada via the TCPL system.[3] A few direct sales of British Columbia gas have been made to eastern Canadian markets through exchange arrangements with shippers of Alberta gas.

About two-thirds of Canadian gas production serves domestic markets, and about one-third is exported to the United States. Figure 2.1 illustrates the flows of Canadian natural gas in 1987.

From the time it commenced operations in 1958 until 1 November 1985, TCPL was essentially the sole purchaser and carrier of gas to Canadian markets east of Alberta.[4] TCPL bought gas from Alberta producers under long term gas contracts and then resold it to local distribution companies in Saskatchewan, Manitoba, Ontario and Quebec under long term sales contracts.

The arrangements under which TCPL operated as a gas sales pipeline made eminent sense in the 1960s and early 1970s. Producers concentrated on exploring for natural gas and developing processing and gathering facilities. Distribution companies in eastern Canada concentrated on developing their systems and marketing natural gas to end-users and did not have to worry about contracting for gas supplies from a multitude of producers.

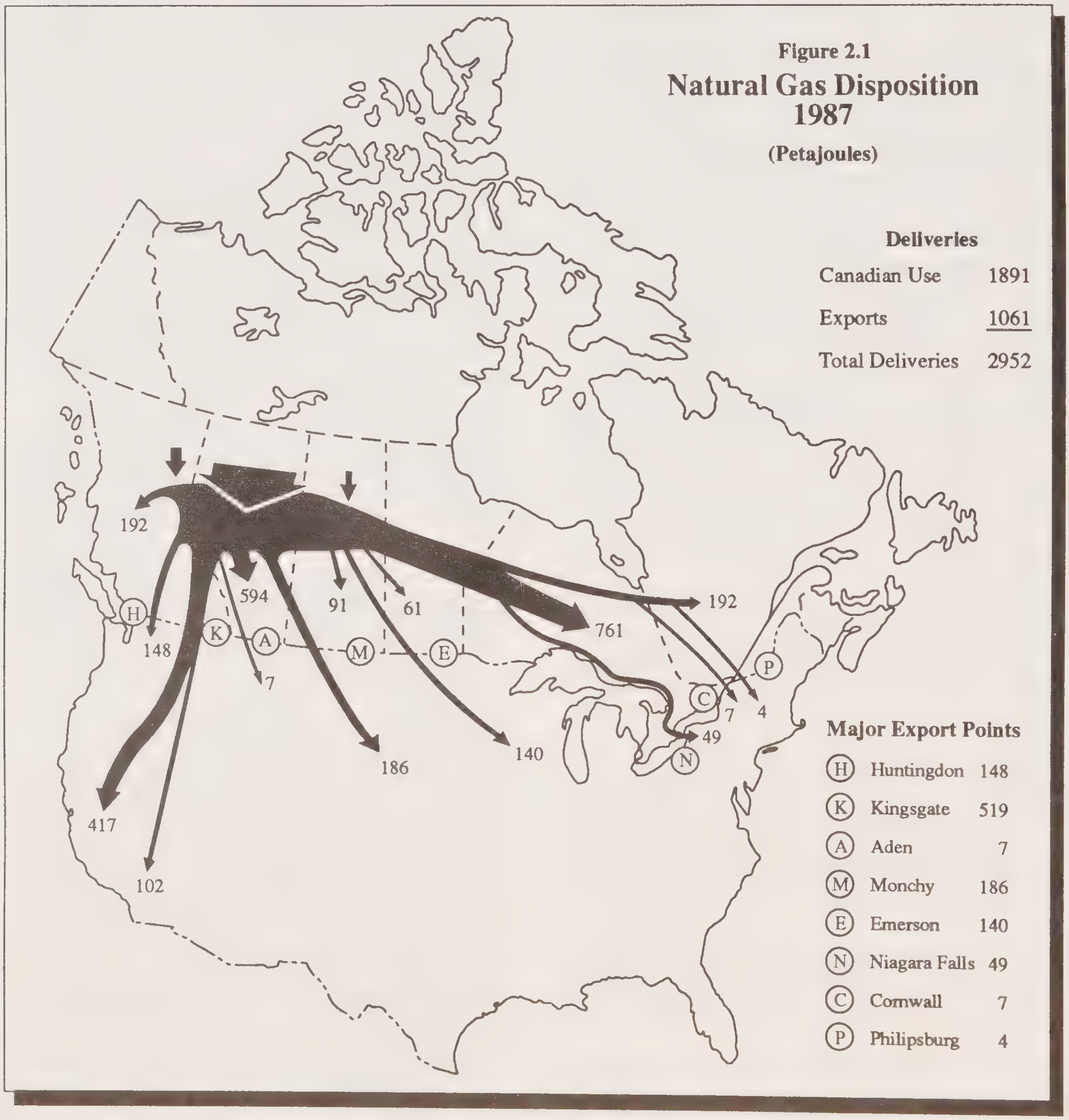
The oil crisis of 1973 led to an approximate fourfold increase in the world price of crude oil. This resulted in upward pressure on the prices of all energy sources, including natural gas. Prior to this time, the price for natural gas in interprovincial trade had been determined by negotiation between producers and TCPL. However, the rapid escalation in energy prices led to government involvement in natural gas pricing in Canada.

The federal government of the day opted for a policy of protecting Canadian oil consumers from the full brunt of the increases in world prices. At the same time, the Alberta government and Alberta natural gas producers wished to obtain prices comparable to those of competing fuels, including prices available in the U.S. gas market. The outcome of nego-

---

1. Formerly Westcoast Transmission Company Ltd.
2. The Saskatchewan Power Corporation (SPC), a provincial crown corporation, was previously responsible for the transmission and distribution of both electricity and gas within the province of Saskatchewan. On 1 June 1988, the Saskatchewan government formed a new crown corporation, SaskEnergy Corporation, to take over sole responsibility for natural gas transmission and distribution in Saskatchewan through its two wholly-owned subsidiairies, TransGas Corporation and Provincial Gas Ltd.
3. Plans exist to connect British Columbia's northeast gas fields with the NOVA system in the near future.
4. Exceptions were some direct sales to Gaz Métropolitain, inc. in Quebec and to Simplot Chemical Company in Manitoba.

This figure illustrates the major flows of Canadian Gas from sources of supply to markets.



tiations between the two governments culminated in the first Canada/Alberta Gas Pricing Agreement, effective 1 November 1975. From 1975 to 1985, the price of Alberta natural gas sold in interprovincial trade was regulated by the federal government under the Petroleum Administration Act (later renamed the Energy Administration Act) at levels agreed to between the governments of Canada and Alberta. The prices for natural gas produced and consumed within the producing provinces were determined by the provincial governments.

Following the 1973 oil crisis, there was widespread concern in both Canada and the United States about the long term adequacy of energy supplies. Gas distribution companies encouraged pipelines to contract for secure supplies of natural gas and many pipelines, including TCPL, actively entered into new long term supply contracts with their producers. To encourage producers to find more reserves, most of these contracts contained generous take-or-pay clauses under which the pipeline companies agreed to take certain minimum annual volumes of gas from the producers and to pay for any gas not taken below these minimum levels.[1] In Canada, minimum bill and take-or-pay clauses in the sales contracts between TCPL and the distributors were removed in 1976 following a decision by the Board which shifted all fixed pipeline costs into TCPL's demand charges. Thereafter, the distribution companies were not obligated to pay for minimum volumes under these contracts.

High regulated prices and guaranteed sales revenue from take-or-pay contracts combined to provide an incentive to both Canadian and U.S. producers to increase their exploration efforts. In Canada, this led to large increases in proven gas reserves by the end of the 1970s. In the United States, the effect was to halt the decline in remaining established gas reserves in the lower 48 states that had been occurring since the late 1960s. The U.S. Natural Gas Policy Act (NGPA) of 1978, which first increased and then decontrolled the prices of "new" gas, further encouraged exploration in the United States.

The Iranian oil crisis of January 1980 led to another large increase in energy prices, again stimulating exploration efforts. Consequently, natural gas supply continued to grow rapidly in Canada while reserves increased slightly in the United States.

By the early 1980s, the consuming sector of the natural gas industry in North America was undergoing a profound change. Due to high energy prices, many energy-intensive industries adopted strategies to minimize their fuel consumption costs including, for example, the installation of fuel-switching capability and more fuel-efficient production facilities. In the United States, the Fuel Use Act (1978) also prevented gas from being used for industrial boiler fuel and prohibited the construction of new gas-fired electricity generation capacity. These developments, combined with the economic recession of 1982, led to a large decrease in U.S. gas demand and, in Canada, to a slowing of growth in domestic gas demand.[2]

---

1. TCPL also signed a number of area contracts with its producers which committed TCPL to take certain minimum volumes of all gas found by the producers within the contract area.
2. Canadian gas exports to the United States fell during this period. While this was due in part to falling gas demand in the United States, the regulated price for Canadian gas exports, which was high relative to both the average cost of U.S. domestic gas and the cost of alternative fuels, was an important factor.

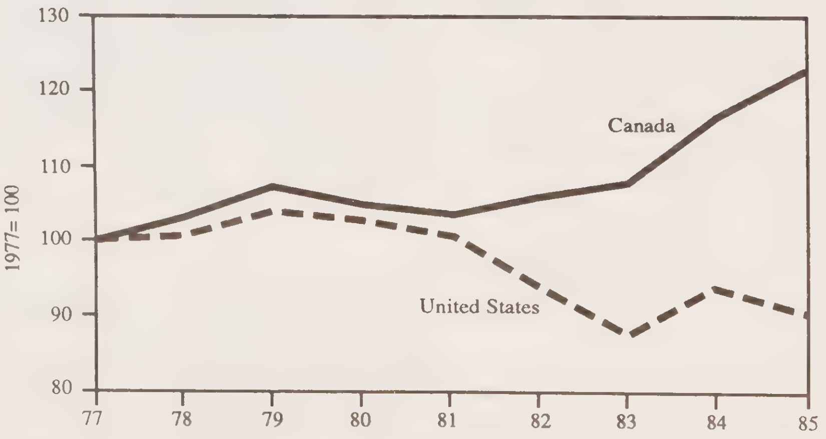
Comparison of Demand Growth
Canada vs. U.S.

During the period 1977 to 1985, the demand for natural gas in Canada and the U.S. experienced markedly different growth patterns. The demand for gas in Canada grew by 20 percent while U.S. domestic demand fell by 14 percent (Figure 2.2). Since U.S. gas consumption was over 10 times greater than Canadian gas consumption in 1977, the overall effect was a decline in combined U.S.-Canadian gas demand of about 11 percent over this period.

There were several reasons for the relatively weak demand for natural gas in the U.S.

- *Total energy consumed per dollar of GNP in the U.S. declined by 23 percent since 1977.*
- *Gas was prevented from participating in the growth in demand for electrical generation by the U.S. Fuel Use Act of 1978 which effectively prohibited the construction of new gas-fired plant.*
- *During the early 1980s gas lost market share due to a lack of flexibility in pricing and other sales terms. The reluctance of pipelines to open up their systems to third parties further frustrated the gas marketing process.*

Figure 2.2
Growth in Gas Demand*
Canada and United States



* U.S. data from Department of Energy EIA Report 0130 Natural Gas Monthly.

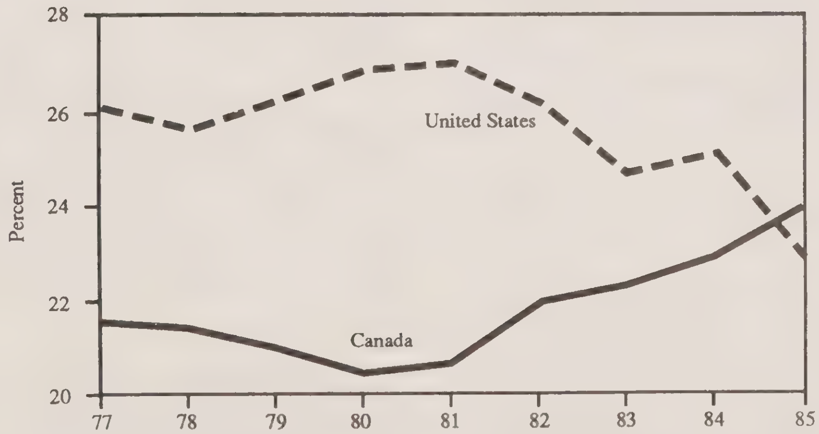
In contrast, government policy in Canada encouraged the consumption of natural gas, particularly as an alternative to imported oil.

- *Prices for gas flowing east of Alberta were held to levels which made it an attractive alternative to oil.*
- *Programs were put in place to encourage households and businesses to switch from oil to gas, electricity or other energy forms.*
- *Financial assistance was given to utilities to encourage expansion into new market areas and to the Trans-Quebec and Maritimes Pipeline Ltd. to extend natural gas service from Montreal to Quebec City.*

The effect was to increase the natural gas share of total energy consumption in Canada from 22 percent in 1977 to 24 percent in 1985 while it fell from 26 percent to 23 percent in the United States (Figure 2.3).

Figure 2.3

Natural Gas Share of Total Primary Energy Demand* Canada and United States



* U.S. data from Department of Energy EIA Report 0130 Natural Gas Monthly.

The combination of falling overall demand and increasing supply led to the emergence of a large excess of productive capability above aggregate demand in the North American gas market, more commonly referred to as the "gas bubble" (Figure 2.4).

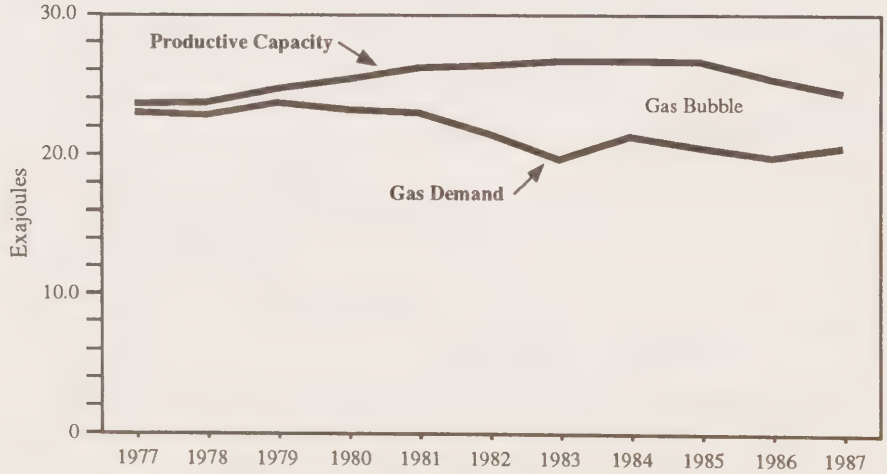
With falling gas demand, many North American pipeline companies found themselves owing enormous sums for gas that they were contractually obligated to purchase but could not sell. For example, by the end of October 1981, TCPL had paid approximately $1 billion to producers for gas it could not sell. Given the poor outlook for demand, most pipeline companies were forced to attempt to extricate themselves from their take-or-pay obligations.

In the United States, most pipeline companies sought to buy out their contractual obligations with their producers. Under such an arrangement, a producer would accept a cash settlement in return for releasing the pipeline company from its take-or-pay obligations. The pipeline company would release the producer from its obligation to deliver gas to the pipeline and the producer would be free to attempt to market its gas. The pipeline company would then apply to the Federal Energy Regulatory Commission (FERC) to allow it to include the costs of the buy-out in its cost of service.

Producers, however, were generally reluctant to release pipelines from their take-or-pay commitments, partly because they had little

Figure 2.4

Combined Canada and United States Productive Capacity and Demand*



* See Appendix D for footnotes.

opportunity to market their gas directly. Most pipeline companies in the United States were not contract carriers and would not willingly carry gas for third parties, particularly if it would displace their own sales.

In Canada, rather than attempting to negotiate the release of its producers' gas, TCPL and its producers opted for an arrangement known as the TOPGAS agreements. This involved two financial agreements between TCPL, its producers and TOPGAS Holdings Ltd. and TOPGAS Two Inc., two consortia of banks and financial institutions. Under these agreements, entered into in 1982 and 1983, the TOPGAS consortia assumed TCPL's outstanding gas payment liabilities and advanced $2.3 billion to the producers. In return, the producers agreed to reduce TCPL's future take-or-pay liabilities.[1]

TCPL's producers are obligated to deliver gas to cover the principal and interest owing on the TOPGAS advances. The principal payments are recovered out of the revenues from the gas sales of each producer's production over the first five months of each gas year. The interest payments are collected by TCPL through a charge on the producers in TCPL's Alberta cost of service. Thus, TCPL essentially acts as a collection agency in the arrangement. However, TCPL has an unlimited liability to the TOPGAS consortia in the event that producers default on payment of the TOPGAS carrying charges and it is also liable for up to $355 million in the event that producers default on repayments of the principal.

Although the TOPGAS agreements alleviated TCPL's take-or-pay problem, TCPL and its producers still faced the underlying problem of a large surplus of gas productive capability. Many producers in both Canada and the United States had incurred large debts in financing the exploration and development of new reserves and were anxious to see changes that would allow them to market this gas. Canadian producers particularly desired improved access to the U.S. export market. Meanwhile, increasingly sophisticated end-users in the industrial sector with fuel switching capability were demanding more flexible supply arrangements, including services such as off-peak cut-rate interruptible transportation service. However, most gas suppliers were unable to respond to these demands due to the regulated structure of prices, inability to obtain access to pipeline capacity, and the existence of long term gas purchase and gas sales contracts.

Governments and regulatory agencies in both Canada and the United States recognized the need to introduce flexibility into the market to better satisfy end-user needs and to provide incentives to the supply industry.

In Canada, the Western Accord of 29 March 1985 between the federal government and the three western producing provinces recognized that a *"more flexible and market-oriented pricing mechanism is required for the domestic pricing of natural gas."*[2] The Accord was followed by the Agreement on Natural Gas Markets and Prices on 31 October 1985. The intent of this Agreement was to *"create the conditions for such a regime, including an orderly transi-*

1. TCPL's take-or-pay obligations were suspended for a two-year period until 31 October, 1988 following the netback pricing agreements negotiated between Western Gas Marketing Limited and its producers in October 1986. TCPL and its producers are currently renegotiating TCPL's take-or-pay commitments.
2. The Western Accord, An Agreement between the Governments of Canada, Alberta, Saskatchewan and British Columbia on Oil and Gas Pricing and Taxation, page 3.

tion which is fair to consumers and producers and which will enhance the possibilities for price and other terms to be freely negotiated between buyers and sellers."[1]

As of 1 November 1985, consumers could contract with producers for direct sales at negotiated prices for new gas supplies or as their existing contracts expired. Distributors could also enter into direct purchase arrangements at negotiated prices for volumes which were additional to those committed under existing contracts. It was expected that, after a one-year transition period, producers and distributors could renegotiate prices in existing contracts to take effect in the 1986/87 contract year. Since 1 November 1986, the price of gas in interprovincial trade has been determined by negotiation between buyers and sellers.

The Agreement also provided for enhanced access to export markets, primarily by relaxing controls on export prices and by removing limitations on volumes of gas exportable on a short term basis.[2]

To many observers the Agreement represented a compromise between the interests of the producing provinces and the interests of the consuming provinces.[3] The producing provinces were provided with enhanced access to export markets while the consuming provinces would be provided with flexible supply options. There was a general perception that both gas producers and consumers would benefit from the increased market flexibility provided by the introduction of freely negotiated pricing and the direct sales option.[4]

In summary, the opening up of pipelines to direct sales came about largely in response to the underlying excess supply hanging over the market in the early 1980s. In these market circumstances, governments recognized that increased flexibility was necessary to ensure the long term health of the supply industry and to ensure that gas users would have access to competitively priced energy sources. In both Canada and the United States, these goals were determined to be best achieved through the introduction of competition into the marketplace and a shift in decision-making away from governments, regulatory agencies and pipeline companies towards individual producers and end-users.

1. Agreement Among the Governments of Canada, Alberta, British Columbia and Saskatchewan on Natural Gas Markets and Prices, Clause 1.
2. Remaining federal regulation over natural gas exports is reviewed in Appendix A.
3. Consuming provinces are the provinces of Manitoba, Ontario and Quebec, which purchase virtually all of their natural gas needs from western Canada.
4. While the Natural Gas Agreement was being implemented in Canada, in the United States the FERC was seeking to encourage interstate pipelines to adopt open access policies and thereby introduce direct sales to the entire United States market. Developments in the United States market over the last few years are further discussed in Section 4.2.

Chapter 3

The Structure and Functioning of the Canadian Natural Gas Market

The introduction of direct sales into the interprovincial gas market at freely negotiated prices has profoundly changed the way in which business is conducted in the market.

Prior to the implementation of the 1985 Gas Agreement, almost all interprovincially traded gas was sold under relatively few gas sales contracts between TCPL and the local distribution companies. Since 1 November 1985, there has been a dramatic increase in the number of direct sales and in the number of buyers and sellers active in the market (Table 3.1).

Table 3.1
Short Term Firm Transportation Service on TCPL*

	Dec. 31 1985	Dec. 31 1986	Dec. 31 1987	May 13 1988
No. of Contracts†	0	24	214	354
Total Volume (petajoules/year)	0	70	210	240

* Information provided by TCPL in Attachment 4, Schedule 7, Response to NEB Information Request dated June 1988, in the public hearing on TCPL's tolls application, RH-1-88.

† The data represent contracts between TCPL and shippers for firm transportation service on the TCPL system. Each contract represents a direct sale to an end-user but, in about two-thirds of the cases, the shipper was a distributor.

As discussed in Chapter 2, at the time the 1985 Gas Agreement was signed, there was a large surplus of gas productive capability above the level of demand at the regulated price. In these market circumstances, the introduction of direct sales into the interprovincial market at freely negotiated prices inevitably led to downward pressure on gas prices. The abrupt fall in world oil prices in the first quarter of 1986 resulted in intense competition for the industrial boiler fuel market from heavy fuel oil, putting further downward pressure on natural gas prices.

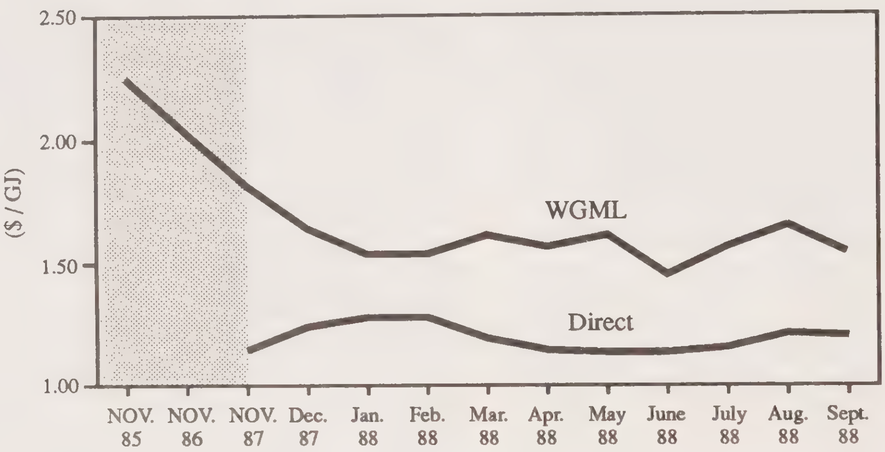
Since 1 November 1985 prices for Western Gas Marketing Limited's (WGML) gas sales to industrial end-users have declined by \$1.00/GJ to \$1.50/GJ due to intense price competition from direct sellers and falling oil prices.[1] However, prices of WGML's gas sold to distributors for eventual consumption by residential and small commercial end-users have only declined by \$.60/GJ. As a result, although average field prices of WGML's gas sales have declined, these prices are still about \$.40/GJ higher than average direct sales prices (Figure 3.1).

Together, Table 3.1 and Figure 3.1 summarize the essential elements of the events in the domestic natural gas market over the last three years. First, there has been a rapid increase in direct sales as end-users have sought out low cost supplies and producers have attempted to sell uncontracted gas reserves. Second, there has been a steep decline in natural gas prices due to excess productive capacity, to competition between gas sellers, and to the general fall in world energy prices.

Although the data portray recent market developments, they mask the difficulties that all market participants have shared in adjusting to the intricacies of conducting business in the new market environment.

1. On 1 January, 1986, TCPL formed WGML to act as its sole gas purchasing and marketing agent, thereby separating these functions from the gas transportation function of the parent company.

Figure 3.1
Alberta Field Prices
WGML System Gas Sales and Direct Sales*



* See Appendix D for footnotes.

The introduction of direct sales at freely negotiated prices has brought new flexibility to the market, but it has also resulted in the creation of a dynamic competitive environment, posing both new opportunities and new risks to all participants.

The purpose of this chapter is to provide a review and an assessment of the structure and functioning of the new domestic gas market. To do this, it is necessary to review the commercial arrangements and regulatory approvals which must be in place for gas to flow from a producer to an end-user.

Section 3.1 provides a brief review of the gas purchase options facing end-users in the new market. Section 3.2 considers the nature and status of gas purchase contracts with producers. Section 3.3 reviews the process of obtaining gas removal permits from the producing provinces and considers the effect of provincial royalty systems on direct sales. Section 3.4 reviews the process of obtaining the necessary transportation space on the provincial gathering systems, on TCPL, and on the local distribution companies. Section 3.5 provides a review of the empirical evidence on natural gas prices being charged to different end-users in Canadian markets and a comparison of prices charged for Canadian gas in Canadian and United States markets. Finally, Section 3.6 concludes the chapter with a summary assessment of the functioning of the domestic market.

3.1 Gas Purchase Options

Prior to the implementation of the 1985 Gas Agreement, most end-users simply purchased gas from their local distribution company at a fixed rate per unit of gas purchased. In most cases, the end-user would not have been aware of the separate charges for gas, for transportation on TCPL, for storage services or for delivery on the local distribution system. The introduction of direct sales into the market has created an array of purchasing options from which gas consumers may choose.

The distinguishing characteristic of a direct sale is that the pipeline company does not take ownership of the gas but, rather, provides transportation service (T-service) for the contracting parties. In a direct sale, the end-user enters into a gas purchase agreement with a producer or producer representative.[1] The shipper is the party who takes ownership of the gas at each point along the gas transportation chain. The shipper may be the producer, the end-user, a distribution company, a broker or an agent representing the end-user(s).

For example, an end-user might purchase gas from a producer in Alberta and, under the terms of the contract, take ownership of the gas immediately east of the Alberta border. In this case, the producer would be responsible for arranging transportation on NOVA and would be the shipper on the NOVA system. The end-user would be the shipper on the TCPL and local distribution systems.

One variation on the above arrangement is a "buy/sell" deal arranged between an end-user and a distributor. For example, an end-user may purchase gas from a producer in Alberta, resell the gas to a distribution company immediately east of the Alberta border and repurchase the gas from the distributor at the plant-gate.[2] The distributor is responsible for obtaining transportation service on the TCPL system and the distributor continues to provide storage and load-balancing services to the end-user, as it would under a traditional system gas purchase (Figure 3.2).[3]

System gas generally refers to gas owned and sold by pipeline companies, including WGML, the marketing arm of TCPL. An end-user may purchase system gas from its local distribution company under traditional purchase arrangements or it may purchase system gas directly from WGML.

Direct sales of system gas by WGML are currently known as system gas resales (SGRs).[4] In an SGR, an end-user purchases gas from

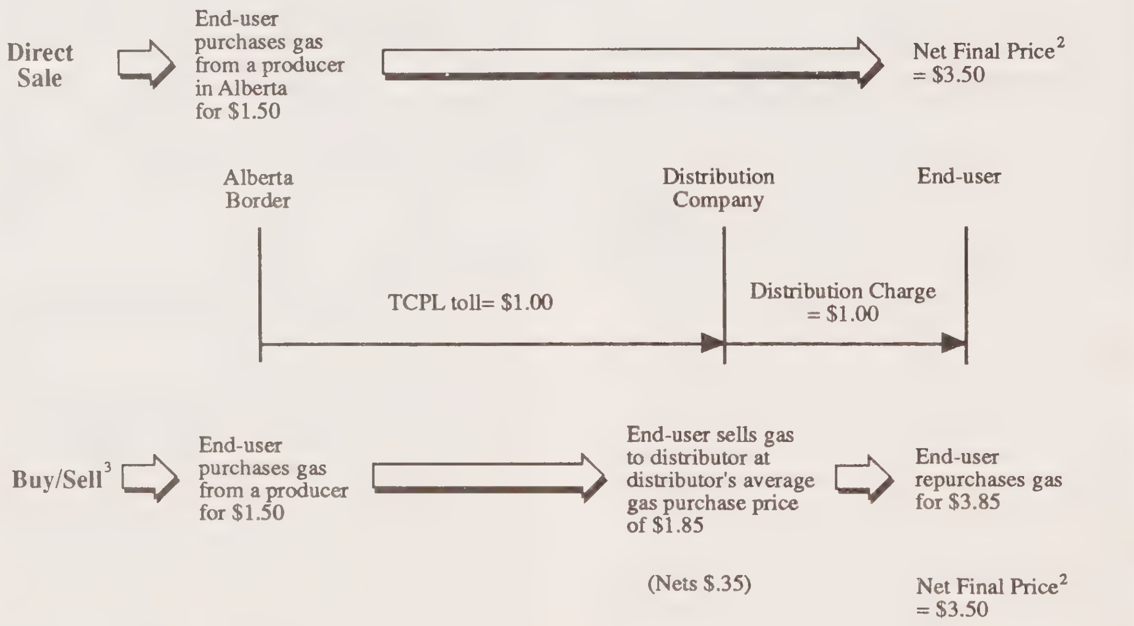
1. A sale will more normally involve a group of producers. For convenience the term "producer" is used to represent either a single producer or a producer group.
2. A buy/sell may also take place at the distributor's inlet from TCPL. In this case, the end-user, a producer or a broker would be the shipper on TCPL.
3. An industrial end-user's daily gas requirements can vary widely and it is difficult to match daily production to daily demand. Therefore, an end-user requires the distributor to store gas on days when the end-user's requirements are below average daily contracted volumes and to increase deliveries when the end-user's requirements are above average daily contracted volumes.
4. SGRs were introduced by WGML and TCPL on 1 January 1988 and replaced WGML's earlier competitive marketing programs (CMPs). WGML terminated its CMPs after the Ontario Energy Board (OEB) stated that, in its view, the pricing scheme under which CMPs were offered was unduly discriminatory. However, the main effect of the change was to remove the transaction from the jurisdiction of the OEB; in an SGR the gas is initially bought and resold within Alberta. There was no real change in the pricing scheme under which SGRs were offered.

WGML immediately east of the Alberta border at a "discounted" price. The end-user then resells the gas to TCPL at the Alberta border for the average cost of gas to the distributor. TCPL then sells the gas to the distributor for this average price plus TCPL's transmission charges and, finally, the end-user repurchases the gas from the distribu-

Figure 3.2

Direct Sales and Buy/Sells [1]

($ / GJ)



1 Prices and tolls are illustrative only.

2 Although the figure shows the net final price being equal for the illustrative direct sale and the illustrative buy/sell, actual prices in direct sales, buy/sells and SGRs depend upon the outcome of negotiations between the buyer and the seller.

3 The figure illustrates a buy/sell in which the end-user sells gas to the distributor at the distributor's inlet. In this case the end-user is the shipper on TCPL. In a second type of buy/sell, the end-user sells the gas to the distributor just inside the Alberta border and the distributor acts as the shipper on TCPL. In a system gas resale, an end-user purchases gas from WGML just inside the Alberta border at a negotiated price and immediately resells the gas to TCPL for the system average price. The end-user finally repurchases the gas from the distributor for the average system price plus the toll charges on TCPL and the distributor's system.

tor at its plant-gate.[1] As in a buy/sell arrangement, an SGR offers the advantages of the distributor providing storage, load-balancing, and back-stopping supply services to the end-user.

3.2 Gas Purchase Contracts

Traditionally, the major pipelines were responsible for contracting for sufficient gas supplies to satisfy the requirements of their downstream customers. In order to provide security for pipeline financing and to ensure a minimum guaranteed cashflow to the producer, gas purchase contracts were generally of a long term nature, typically 25 years. Consequently, most established economic gas reserves are dedicated to the major pipeline companies or their affiliates under long term gas supply contracts.

About 85 percent and 58 percent of the established reserves in Alberta and Saskatchewan respectively are dedicated to shippers under either long term or short term contracts (Table 3.2). In Alberta, WGML currently holds about 2500 long term gas purchase contracts with approximately 750 producers, accounting for about 33 percent of Alberta's current established gas reserves and 44 percent of current productive capacity. Pan-Alberta Gas Ltd. (Pan-Alberta) holds about 1200 long term supply contracts with 420 producers, accounting for about another 10 percent of Alberta's current established reserves and 14 percent of productive capacity. Alberta & Southern Gas Co. Ltd. (A&S) has about 8 percent of Alberta's current reserves under long term contract accounting for another 10 percent of productive capacity. Thus, between them, WGML, Pan-Alberta and A&S have about 68 percent of the total current productive capacity of Alberta gas under long term contract.

Table 3.2
Gas Reserves
Contracted and Uncontracted
December 31, 1986[1]
(exajoules)

	Reserves Under Contract	Uncontracted Reserves	Total Reserves
Alberta	54.5[2]	9.4[3]	63.9
(%)	(85%)	(15%)	(100%)
B.C.	5.5	3.3[4]	8.8
(%)	(62%)	(38%)	(100%)
Saskatchewan	1.1	.8	1.9
(%)	(58%)	(42%)	(100%)
TOTAL	61.8[5]	13.5	75.3[5]
(%)	(82%)	(18%)	(100%)

1. Latest data available at time of writing.
2. This also includes gas reserves that have been set aside for future use in enhanced oil recovery and other liquids recovery projects.
3. This includes about 2 exajoules which is currently beyond economic reach.
4. Some small amount of this gas is in fact under contract but, at the time of writing, the exact volumes were not available.
5. The total includes 0.7 exajoules from other areas in Canada, mainly from Ontario.

1. Consider the following example. The end-user purchases gas from WGML at $1.50/GJ at the Alberta border and resells this gas to TCPL at the system average price, say, $1.85/GJ. TCPL sells the gas to the distributor for the system average price of $1.85/GJ, plus TCPL's transmission charge. Finally, the distributor sells the gas to the end-user for $1.85/GJ plus TCPL's transmission charge and distribution charges. The cost of the gas to the end-user, net of TCPL's transmission charges and distribution charges, is $1.85 - ($1.85-$1.50) = $1.50/GJ.

The remaining contracted volumes are dedicated to other shippers under both long and short term contracts. The end-use markets for this gas include intra-Alberta markets, interprovincial markets and export markets. As short term contracts expire, some contracted gas becomes "uncontracted" and it is therefore difficult to estimate exactly how much gas is available for new sales at any point in time.

In Saskatchewan, about 45 percent of established reserves are under contract to Provincial Gas Ltd. and are thus essentially reserved for provincial consumption. However, the government of Saskatchewan has been very supportive of extra-provincial sales of Saskatchewan gas since the implementation of the 1985 Gas Agreement. In February 1987 the Saskatchewan Power Corporation (SPC) renegotiated its producer contracts to provide for a 20 percent reduction in SPC's rates-of-take from provincial gas producers, thereby freeing this gas up for the direct sales market. Further, on 1 May 1988, the SPC sold approximately 830 petajoules of its own gas reserves to SaskOil Ltd.[1] Whereas these reserves were previously reserved for the SPC's own consumption, SaskOil is now free to market this gas in both intra-provincial and extra-provincial markets.

The situation in British Columbia is unique because, prior to 1984, all gas purchase contracts with B.C. producers were held by the British Columbia Petroleum Corporation (BCPC), a provincial crown corporation. In that year, the B.C. government first allowed direct sales to export customers and, in 1986, introduced direct sales within the province. In the last two years, direct sales of B.C. gas have grown rapidly and a number of parties, including B.C. industrial customers and Westcoast Energy Inc., now hold gas purchase contracts with the producers. However, about 85 percent of the gas reserves under contract are still held by the BCPC.

The B.C. government has announced that it intends to privatize the BCPC in the near future. If the crown corporation were sold, the purchaser would then likely hold the gas purchase contracts.

As discussed in Chapter 2, most of the gas under long term contract in Alberta was contracted for prior to 1980 when there was an expectation that gas demand would continue to grow rapidly and that supplies would be inadequate to meet demand. Subsequently, a situation of excess supply developed in the early 1980s and pipeline companies, including TCPL, were unable to honour their commitments to purchase gas under contract with Alberta producers.

Many of TCPL's system producers also own reserves of natural gas that are currently uncontracted. This mix of contracted and uncontracted gas reserves combines to create an interesting market situation. For example, if a system producer makes a direct sale to a market previously served by system gas, of which its gas formed part of the supply, its rate of production and revenue from its system gas sales will fall. However, if the producer is able to obtain a high rate of take on the new direct sale, it can be better off making the direct sale, even at a discounted price. Thus, although system gas producers as a group are worse off when a direct sale

1. Although Provincial Gas Ltd. has been responsible for the distribution of natural gas in Saskatchewan since 1 June 1988, the SPC retained ownership of these gas reserves until they were sold to SaskOil.

displaces a system sale, the individual producer making the direct sale can be better off.

Under the TOPGAS agreements, TCPL is obligated to attempt to maximize sales of system gas. Further, it is not in TCPL's interest to see system gas sales displaced by direct sales.

In summary, most established gas reserves in Alberta are under long term contract to pipeline companies and are not available to the direct sales market. At the same time, many producers in all three producing provinces own volumes of uncontracted gas reserves which they would like to sell.

It is the existence of uncontracted reserves that is providing the major impetus behind the activity in the direct sales market.

These circumstances have created a substantial degree of competition in the Canadian natural gas market. On the one hand, TCPL, the TOPGAS consortia, and the major system gas producers have been fighting to maintain the market share of system gas sales. On the other hand, producers holding substantial uncontracted reserves, gas brokerage firms and many end-users support the continued development of the direct sales market. As long as substantial reserves of uncontracted gas overhang the market, there will continue to be competitive pressure exerted on both system and non-system gas prices.

3.3 Producer Province Regulation - Removal Permits and Royalties

All three producing provinces currently require producers to obtain provincial approval before gas is removed from the province (i.e. sold to out-of-province end-users).

It is the government of Alberta's view that so-called "core" market customers in the consuming provinces should be required to purchase gas under long term contracts.[1]

This view was expressed by Dr. Neil Webber, Minister of the Alberta Department of Energy and Natural Resources as follows:

"I would very much like to see an expanded role for market forces in the natural gas business. I, therefore, recommend that all Ontario consumers be given the option of purchasing gas from either a distributor, a broker or directly from a producer. Consumers identified as being particularly sensitive to security of supply would be required to demonstrate that they have maintained a secure dedicated supply situation through the contractual process if they wish to choose the broker or direct purchase option. Distributors would have to ensure their portfolio includes long-term dedicated contracted supply for the portion of their market particularly sensitive to security of supply"[2]

It has been the policy of the Alberta government to not issue removal permits for short

1. It is the policy of the government of Alberta that the core market in Alberta, defined as residential and commercial gas users who are not in a position to use alternative fuels, must be protected by long term contracts (Government of Alberta News Release, April 14, 1987). The term "core market" is generally used to refer to gas-users who cannot readily switch to alternative fuels and who are therefore considered to be "captive" customers. However, there is no generally accepted definition of what constitutes a core market customer.
2. Letter from Neil Webber to Robert Wong (Minister of Energy, Ontario), 15 July 1988.

term direct sales to end-users which, in Alberta's view, would be more appropriately served under long term contracts. It is also Alberta's policy to not issue removal permits for direct sales contracts under which gas is destined for end-users who consume less than 35,000 GJ per year. Consequently, small industrial and commercial end-users are constrained in their ability to make direct purchases of Alberta gas.

On 20 May 1988 the Alberta government introduced Bill 41 in the provincial legislature to provide for increased financial penalties to parties who are found to be contravening the *Gas Resources Preservation Act* by removing gas without the required permits. The amendments under this bill would also empower the Alberta government to cut off the gas supply of any shipper found to be in contravention of the Act.

On 1 January 1988, the Alberta government changed its royalty system so that gas royalty rates are now based on an Alberta average market price (AMP) as well as the actual selling price.[1] The royalty rate is applied to the producer's actual selling price except in instances where this price is below 80 percent of the AMP. In these instances, the royalty is calculated against 80 percent of the Alberta AMP. The royalty system still makes a distinction between old gas and new gas such that the applicable royalty is lower on new gas.[2]

The intent of the change was primarily to protect the province's royalty share of natural gas sales revenues. However, one effect of this new system is to discourage direct sales of non-system gas priced below 80 percent of the Alberta AMP. Since royalties on system gas sales are based on an average selling price, system gas sales under a netback pricing arrangement may be made below 80 percent of the AMP without incurring the higher royalty rate. In contrast, producers who only make a few direct sales have less ability to roll in their lower priced sales with higher priced sales. Consequently, they may pay a higher royalty rate on low priced direct sales than is applied to system gas sales.[3]

Under Saskatchewan's gas removal permitting process, prices for gas leaving the province must not be lower than those paid by provincial consumers for similar types of sales and removal permits will not be issued for sales which displace Saskatchewan sales presently under contract. However, no distinction is made with respect to the type of end-user; hence, many smaller industrial and commercial class end-users have entered into direct sales contracts with Saskatchewan gas producers in the last two years.

1. The government of Alberta sets and publishes the AMP every month according to its assessment of the average field value of Alberta natural gas.
2. Old gas is any gas in a pool from which production commenced prior to 1 January 1974. All other gas is considered to be new gas.
3. For example, the Alberta AMP was set at $1.56/GJ in January 1988 and the minimum price against which royalties were calculated was $1.25/GJ. If the average price of system gas sales were $1.80/GJ, then all system sales would pay a royalty against this price even if some sales were made under the SGR program at, say, $1.10/GJ. In contrast, if a producer made a direct sale at $1.10/GJ and had no offsetting direct sales at a higher price, it would pay a royalty based on a price of $1.25/GJ, thereby reducing its profit margin.

Due to the provincial government's policies and to agressive gas field development in the last few years, Saskatchewan's extra-provincial sales of gas have increased from zero in 1985 to an expected 40 petajoules in 1988.[1]

Saskatchewan crown royalties are calculated as a percentage of field-gate prices and, as in Alberta, make a distinction between old and new gas. Unlike Alberta, there is no minimum royalty applied to direct sales. Instead, the government has stated that it will monitor gas prices and has indicated that it reserves the right to apply a specific royalty to any gas sold at below market value.

British Columbia's removal permit regulations require that prices charged for gas removed from the province not be less than prices charged to B.C. customers in the market area adjacent to the export point for sales on similar terms and conditions.

The gas royalty in B.C. is set at a base of 15 percent for non-oil-associated production and increases as wellhead prices move above an established minimum, currently set at $52 per 1000 cubic metres ($1.40/GJ).

In summary, the responses of the three producing provinces to the introduction of direct sales have been markedly different. Alberta has been concerned about the erosion of gas prices and gas royalty revenues due to price competition from direct sales and has had a restrictive removal permit policy in place.

In contrast, it has been the policy of the Saskatchewan government to encourage direct sales of Saskatchewan gas in both intra-provincial and extra-provincial markets. Alberta's reluctance to approve price-discounted sales to smaller end-users has provided an opportunity for Saskatchewan gas producers to establish a market presence in eastern Canada.

For its part, British Columbia has actively supported the development of an intra-provincial direct sales market but, due to the lack of connections between B.C. gas fields and eastern Canadian markets, has not yet been able to participate in the interprovincial direct sales market.

3.4 Gas Transportation

In order to move gas to a market in eastern Canada, a shipper must obtain transportation service on the natural gas gathering system in the producing province, on the TCPL system and on the local distribution system.

Transportation on Gathering Systems in Producing Provinces

Since the implementation of the 1985 Gas Agreement, the number of shippers on both TCPL and the gathering systems in the producing provinces has rapidly increased. For example, the number of firm service contracts that NOVA entered into with shippers for intra-provincial service increased from 413 in 1983 to 3500 in 1987.[2] The increase in both the number of shippers and in volumes shipped in the last three years has increased the complexity of operating the gathering systems. It has also raised issues concerning the manner in which available space should be allocated to shippers.

Firm transportation service on the NOVA system in Alberta has been fully subscribed

1. Based on estimates by the Saskatchewan Department of Energy and Mines.
2. From Canadian Natural Gas Focus, Volume 1, Issue 11, May 1988 (original source: NOVA, Alberta Gas Transmission Division).

since December 1987. It will likely require two years to plan and construct any necessary new facilities to meet requests for additional service received by NOVA on or before 1 August 1988. As a result, shippers who do not currently have contracted firm service on NOVA are experiencing difficulty in making new firm direct gas sales.

The problem, however, has not been solely one of a physical limitation of capacity but also a contractual one. For example, consider a shipper that wishes to make a new direct sale which would displace an existing shipper's sales. If the new direct sale were to proceed and the "displaced" shipper did not find a new market for its gas, the displaced shipper would end up with unused contracted firm space on NOVA. However, because there is currently no agreement amongst shippers on NOVA on a mechanism by which the displaced shipper's entitlement to firm space may be transferred to the displacing shipper, the effect may be to deny space to the shipper making the new sale.

The contractual arrangements by which space is reserved on the NOVA system are more complex than the parallel arrangements on the TCPL system. Shippers on NOVA must reserve receipt capacity at individual receipt points on the NOVA system as well as transportation capacity on NOVA's mainline system. Reserved receipt capacity confers a right on a shipper to inject gas into NOVA's mainline system from the connected gas gathering systems at particular receipt points. However, because shippers hold receipt capacity at different points along the NOVA system, it would not always be possible to transfer receipt capacity from a displaced shipper to a displacing shipper. Further, shippers have contracted receipt capacity for varying lengths of time. For these reasons, the operating demand methodology which the Board has adopted to transfer space on the TCPL system from a displaced shipper to a displacing shipper would not work on the NOVA system.[1]

NOVA has been attempting to find a method by which space on its system could be reallocated from a displaced shipper to a displacing shipper and which would be acceptable to a majority of shippers. NOVA's preferred solution is that displaced shippers voluntarily sub-let space to displacing shippers. However, some shippers are not willing to assign their space to other shippers, even on a temporary basis.

During phase one of the current TCPL toll hearing (RH-1-88) some shippers alleged that WGML was unnecessarily maintaining excess capacity on NOVA, thereby making it more difficult for direct sellers to obtain firm capacity. The basis for this view was that, although annual sales of system gas had fallen by approximately 200 petajoules since the introduction of direct sales, WGML had not reduced its contracted firm capacity on NOVA. For its part, WGML maintained that, if it were to give up the space now, it could be caught short of capacity to meet contractual commitments and space needed to accommodate possible increased sales.

NOVA, in a letter to all shippers on its system and other interested parties, proposed several alternatives for allocating space among firm shippers.[2] NOVA requested comments by 30 June 1988. It is currently considering these responses and preparing a

1. See pages 22-24 for a discussion of the displacement problem on TCPL.
2. Letter from NOVA to Alberta gas shippers and other interested parties concerning access to firm transportation service on the NOVA system, 18 April 1988.

new proposal as to how access to firm transportation service should be determined.

An access problem can arise in another way for a direct seller of gas who does not have sufficient firm receipt capacity under contract on NOVA. Although the capacity of NOVA's gathering system exceeds that of the downstream mainline capacity on TCPL, capacity restrictions may occur at particular receipt points on the NOVA system.

When nominations for gas deliveries exceed the gathering system's capacity at a particular receipt point, NOVA apportions each shipper's nominations. If a direct seller does not have a well diversified portfolio of receipt points or back-up supplies of gas, apportionment may cause it to fall short of the gas necessary to honour its sales contract. In this case, the direct seller may be forced to purchase gas at a higher price from other producers in order not to default on its sales contract.

Before the introduction of direct sales in interprovincial markets, capacity problems at particular receipt points on NOVA rarely created a problem for gas shippers. With the exception of direct sales in the intraprovincial market, gas was bought and sold by a few large shippers, including TCPL, A & S and Pan-Alberta, who had contracted for gas supplies with hundreds of producers. Apportionment would generally not pose a problem for these system gas shippers because any deficiency at one receipt point could be made up by increasing nominations at other receipt points. In the last few years, there has been a dramatic increase in the number of direct sellers shipping gas on NOVA, many of whom only have access to gas supplies at a few receipt points. Thus, the frequency with which shippers, particularly direct sellers, have experienced access problems on NOVA has increased.

A shipper who is concerned about apportionment at its receipt point can request NOVA to construct a new receipt point or modify an existing one. However, as earlier mentioned, NOVA has indicated that it will not be able to install any new facilities to satisfy requests for firm service before the 1990-91 gas year. Prior to making expenditures on new facilities, NOVA requires all shippers who request additional facilities to provide a guarantee, such as a letter of credit, of ability to pay for firm service. Although financial guarantees are a normal aspect of the business, such a requirement may have the effect of putting most of the risk associated with new sales on the shipper.

This problem, however, has been with the producing sector since the inception of the industry. To bring new supplies of natural gas to market, a large investment in transportation facilities is often required. As long as sales are not guaranteed, there has been some risk associated with the construction of new facilities. The question that most often arises is how the risk should be distributed among the various market participants. In a market characterized by private contractual arrangements, the parties are free to negotiate all contract terms and a producer may, for example, accept a lower price if the purchaser is willing to share the risk of default.

The substantial number of direct sales of Saskatchewan gas made to eastern Canada over the past year have strained the physical capacity of the TransGas system, requiring the construction of new facilities. To date, with a couple of exceptions, there has been sufficient capacity to move all gas nominated for delivery.

TransGas, like NOVA, requires shippers who request new facilities to provide financial guarantees as security against the capital costs of construction. Thus, as in Alberta, producers are bearing most of the risk associated with the construction of new facilities.

The Westcoast transmission system in British Columbia has been characterized by excess capacity. However, during the last two years, producers have been placed in a queue to obtain access to gas processing facilities at Fort St. John. This bottleneck has placed a constraint on direct sales of B.C. gas.

Shippers who are in need of new gathering or processing facilities can either build the facilities themselves or request Westcoast to do so on their behalf. In most cases, the costs of new gathering facilities are simply rolled into the overall cost of the Westcoast system and, therefore, all shippers share in paying for the new facilities. However, if the cost of the new facilities results in an average discounted cost of service which exceeds a certain level, Westcoast may apply a surcharge to the shipper who requested the new facilities.

Availability of Transportation Service on TCPL

Since the general introduction of direct sales in the interprovincial market on 1 November 1986, NEB hearings on TCPL's tolls have focussed upon the terms and conditions of access to the TCPL system. Clearly, if direct sales of non-system gas are to compete with system gas sales in central and eastern Canadian markets, access to the TCPL system must be available to all shippers on similar terms and conditions. As previously discussed, TCPL has been concerned about the erosion of the market share held by system sales.

Prior to 1 November 1985, a proviso in TCPL's tariff conditions stated that transportation service would not be provided to shippers in cases where the proposed sale would displace a market previously served by system gas. Under clause 7 of the 1985 Gas Agreement, the signatory governments requested the Board to review TCPL's tariff policy regarding displacement "taking into account, among other things, interested parties' views on the fair and equitable sharing of take-or-pay charges." In addition, the Board was requested to review "whether inappropriate duplication of demand charges will result from possible displacement of one volume of gas by another."

In its May 1986 decision on these matters, the Board directed TCPL to remove the displacement proviso from its tariff.[1] With respect to the sharing of the TOPGAS charges, the Board recommended that Alberta require non-system shippers pay 10¢/GJ during the 1986/1987 gas year, 9¢/GJ during the 1987/1988 gas year and 8¢/GJ during the 1988/1989 gas year. These payments were estimated to be about one-half of the payments per GJ made by system gas shippers in each year.

The Board recognized that requiring non-system gas shippers to share in the payment of the TOPGAS charges would have the effect of raising the minimum price at which non-system gas could be sold and, to this extent, would increase gas prices to purchasers of non-system gas. Nonetheless, in light of the historical circumstances surrounding the development of the take-or-pay problem, the Board recommended that non-system gas

1. National Energy Board Reasons for Decision in the Matter of TransCanada PipeLines Limited Availability of Services, May 1986.

producers in Alberta share part of the TOPGAS carrying charges for three years during a transition to a market-oriented pricing regime. Alberta subsequently passed the necessary legislation under which the sharing of the TOPGAS charges could be implemented and has, to date, maintained the non-system shippers' share at 10¢/GJ. Although this charge may slightly reduce the competitiveness of non-system gas, it has not prevented non-system sellers from offering discounts substantially below system gas prices.

The concern about inappropriate duplication of demand charges was as follows. Distributors had entered into long term gas purchase contracts with TCPL in the expectation that they would continue to require the gas to meet the needs of their customers. Under these contracts, the distributors paid fixed annual demand charges to TCPL plus a commodity charge according to the actual volumes of gas taken. With the advent of direct sales, end-users that previously bought system gas from the local distribution companies began to arrange direct purchases from producers. In these cases, both the distributor and the end-user could have been required to pay demand charges to TCPL as a guarantee of gas delivery; hence, a double-demand charge would have been paid to TCPL.[1]

In its May 1986 decision, the Board decided that inappropriate duplicate demand charges would result from a displacement purchase by an end-user and decided that the distributor's obligation to pay a demand charge should be reduced by an amount equivalent to the displacing direct purchase. This has enabled new direct purchases to proceed without either the distributor or the end-user being required to pay a demand charge for gas it does not require.

A major issue over the last few years has been whether distributors should be permitted to "self-displace". Self-displacement refers to a distributor replacing some portion of its gas purchases from TCPL with purchases from some other supplier.

As discussed above, long term gas sales contracts between TCPL and the major eastern Canadian gas distributors were in place when the 1985 Gas Agreement was signed. Distributors are currently free to purchase incremental volumes of gas from the shipper of their choice. Distributors could also enter into contracts with producers for gas which could potentially displace volumes purchased from TCPL. However, to date the Board has decided that it would be improper to allow access to TCPL for self-displacement volumes and, hence, distributors have been effectively prevented from switching to other suppliers. Further, a distributor could not be assured that Alberta would issue the necessary removal permits. Thus, to date, distributors have not been able to self-displace.

Distributors have argued that they should be allowed to self-displace; i.e. in their view the Board should direct TCPL to transport any displacement volumes which they may purchase from shippers other than WGML and the Board should ensure that they do not pay double demand charges to TCPL as a result of such purchases.

---

1. In practice the end-user would have been required to pay double demand charges; once to TCPL and once to the distributor. This occurred in Ontario, for example, because the Ontario Energy Board required end-users to indemnify the distributors for "unabsorbed" demand charges that the distributors incurred as a result of direct purchases. This requirement effectively removed the incentive for end-users to purchase gas directly from producers.

Distributors have further argued that, because they are effectively bound to their long term gas purchase contracts, WGML is sheltered from competitive forces and there is limited economic incentive for WGML to reduce prices to small end-users who cannot readily switch to alternative fuels. The result, in the distributors' view, has been that prices to many residential and small commercial and industrial customers have remained substantially higher than prices to other customers who have been able to enter into direct purchases.[1] TCPL has argued that the gas purchase contracts are binding and that it would be inappropriate to relieve distributors from their contractual obligations to pay the demand charges.

The Board has heard arguments on the self-displacement issue in three hearings since the advent of open access and, to date, has ruled against distributor self-displacement. The question has been addressed again in TCPL toll hearing RH-1-88 and the Board's decision is pending in January 1989.

On 17 October 1988, WGML announced that it had agreed upon new long term gas sales arrangements with 6 Canadian distributors, including Consumers', ICG (Manitoba), ICG (Ontario), GWG and GMi, but excluding Union. Under these new agreements, the distributors have agreed not to self-displace. According to WGML, the contracts state: *"a distributor can not contract for an additional volume of gas from a third party and then reduce the volume of a previously existing contract, unilaterally. However, each arrangement recognizes that the distributor may be displaced by other gas supplies in both its essential service and industrial markets."*[2]

Another issue which has arisen recently is the question of whether WGML/TCPL's system gas resales (SGRs) are unduly discriminatory. As explained in Section 3.1, in an SGR an end-user purchases gas from WGML at a discounted price just within the Alberta border, resells the gas to TCPL at the system average price and, finally, repurchases the gas at the plant-gate from the distributor for the system average price, plus transmission and distribution charges. An SGR provides the end-user with the advantages of a system gas purchase because the distributor provides storage, load-balancing and backstopping services. However, TCPL has stated that it cannot provide a similar service for non-system gas sales because of its contractual obligations under the TOPGAS agreements to purchase gas only from its system producers; i.e. if an end-user purchases gas from a shipper other than WGML, TCPL will not buy the gas from the end-user at the Alberta border and resell it to a distributor for resale to the end-user. TCPL will provide only transportation service for non-system gas.

In the view of some direct shippers, the fact that SGRs are available only to system shippers provides an unfair competitive advantage to system gas sold under the SGR program.

Regulation and Gas Transportation in the Consuming Provinces

In response to the 1985 Gas Agreement, Manitoba, Ontario and Quebec have adopted new policies regarding the distribution and sale of natural gas within their jurisdictions. Although each province has adopted policies that it has judged most appropriate to its

1. See page 31 for a discussion on domestic gas pricing.
2. Backgrounder to WGML press release of 17 October 1988, page 2.

particular circumstances, the general set of issues was common to all.

Flow-through of WGML's Prices

All three provinces have had to decide whether or not to approve the flow-through of prices, as negotiated between the provincial distributors and WGML, to provincial end-users. As discussed previously, at the time the 1985 Gas Agreement was signed, distribution companies in Manitoba, Ontario and Quebec were committed to purchase most of their gas from TCPL under long term gas sales contracts. In accordance with the Agreement, the prices in these contracts have since been renegotiated between WGML and the distributors on three occasions.[1]

As a result of the initial renegotiations, the distributors, producers and WGML agreed upon a pricing package effective 1 November 1986 which offered substantial discounts to high volume industrial customers and progressively smaller discounts to lower volume industrial customers and commercial and residential (core market) customers.

The discounts to industrial customers were offered under competitive marketing programs (CMPs). WGML and the distributors proposed that the pricing scheme be allowed to flow-through to end-users served by the distribution companies. The issue facing the regulatory bodies in Manitoba, Ontario and Quebec was whether or not they should approve this flow-through of renegotiated system prices.

In Manitoba, prior to price renegotiations between WGML and the distributors, the provincial government imposed a tax on compressor fuel used in the province for transporting gas to eastern Canadian and export markets. In the subsequent negotiations, WGML did not offer the same discounts on Manitoba gas sales that it did for Ontario. The Manitoba load is comprised primarily of residential and small commercial end-users and, hence, Manitoba end-users were not, on average, benefitting from price reductions to the same extent as end-users in other provinces.

In May 1987 the Manitoba government directed the Manitoba Oil and Gas Corporation (MOGC) to act as a purchasing agent for the province's gas utilities. The MOGC contracted directly with a group of producers to supply gas to the province's two distribution companies, Inter-City Gas Utilities (Manitoba) Ltd. (ICG (Manitoba)) and Greater Winnipeg Gas Company (GWG). Subsequently, the MOGC applied to the Board for an order which would have required TCPL to carry MOGC's direct gas purchases. In its September 1987 decision on the matter, the Board stated that the MOGC's proposed gas supply arrangements constituted a self-displacement in substance and that the public interest would not be served by granting such an order. The MOGC subsequently attempted to appeal the Board's decision in the Federal Court of Appeal but the court did not grant leave to appeal.

In Ontario, the Ontario Energy Board (OEB) in November 1986 approved for a six-month period (later amended to one year) rates stemming from a two-year agreement between WGML and Consumers' Gas Ltd (Consumers').[2] The OEB expressed reserva-

1. These contracts are still held by TCPL, but WGML acts as TCPL's agent in all contract negotiations.
2. Similar agreements between WGML and Union and ICG (Ontario) were also approved by the OEB.

tions about approving the 1986 agreement, which provided for a \$0.32/GJ reduction in the base price of gas at the Alberta border from \$2.80/GJ to \$2.48/GJ[1] and a range of further discounts for industrial customers, stating that it was being asked to approve rates that *"would be set on a basis of criteria to which it was not a party"*.[2] The OEB also argued that it was being asked to approve rates that would *"effectively require it to abandon a part of its jurisdiction to others, possibly lead to undue discrimination, and be based on an agreement with a lifespan of two years, that may prove to be too long"*.[3] It asked Consumers to renegotiate prices with WGML so that its concerns would be addressed in a new agreement.

WGML did renegotiate these contracts with Ontario distributors for the 1987/88 gas year. The new agreements contained the same base price of \$2.48/GJ but added some new discounts including a \$0.30/GJ discount on summer volumes. Upon reviewing these agreements in January 1988, the OEB found that the negotiations failed to produce an agreement which addressed its previous concerns. The OEB reluctantly approved the agreement for another year stating that *"prevailing circumstances outside Ontario prevented Consumers' from meeting the criteria."*[4] The OEB went on to enumerate its views on the impediments to the implementation of a fully competitive market:

"• *the long term contracts between TCPL and Consumers' and the inability of the latter to self-displace contracted volumes with gas from other sources, thus preserving TCPL's monopoly;*

• *the present TOPGAS arrangements and the potential additional problems arising when the moratorium on "take-or-pay" ceases in 1988; and*

• *the Alberta Government's policies on removal permits."*[5]

The OEB suggested that appropriate action to remedy these impediments could include a *"partial decontracting provision"*[6] in utilities' supply contracts with TCPL which would allow for a gradual reduction in contract volume over a reasonable period of time, an *"imaginative solution"*[7] to the TOPGAS problem so that it does not hamper decontracting by utilities, and the *"elimination by the Alberta government of all constraints on removal permits."*[8] In addition, the OEB reiterated its opposition to CMPs suggesting that they be replaced by direct sales.

In contrast, La Régie du Gaz Naturel (the Régie), the provincial regulatory body in Quebec, approved the renegotiated prices between Gaz Métropolitain inc. (GMi) and WGML without noting any serious reservations. This may be, in part, due to the nature of the Quebec gas load which is comprised primarily of industrial end-users.

The new long term gas sales contracts signed in October between WGML and 6 Canadian distributers provide for a two-year pricing agreement under which a \$0.60 demand-charge and a \$1.60 commodity charge will be applied to "core" market customers in

1. Although the Alberta border price fell by \$0.32/GJ, the reduction in the base price of system gas as delivered to distributors in eastern Canada only fell by \$0.20/GJ because a \$0.12/GJ federal transportation subsidy ended on 31 October 1986.
2. OEB, Partial Reasons for Decision, E.B.R.O. 414-1, 28 November 1986, p.10.
3. ibid. p.10
4. OEB, Decision with Reasons, E.B.R.O. 410-111, 414-11, 417, 22 January 1988, p.38.
5. ibid. p.70
6. ibid. p.72
7. ibid. p.73
8. ibid. p.70

Ontario and Quebec, yielding an Alberta border price of $2.20/GJ at a 100 percent load factor. The price to Manitoba core market customers simply consists of a $2.20/GJ commodity charge. These prices are to be effective until 31 October 1990 and are subject to renegotiation thereafter.

Under these new arrangements, the price of system gas destined for industrial users under SGRs will be negotiated against a base of $2.20/GJ at the Alberta border, and will consist of a straight commodity charge.[1] Thus, the new arrangements effectively continue the past practice of "streaming" system gas by price to different classes of end-users.

These new agreements have been approved by TCPL's system gas producers but they have not yet been approved by the regulatory agencies in the consuming provinces.

Role of Distributors and Gas Brokers

Each province has had to decide what the appropriate role of the local distribution companies (LDCs) should be in the new market and what range of services they should offer to end-users. There are a number of sub-issues which have arisen with respect to this question, including the appropriate role of brokers, the desirability of the separation of the sales and transmission functions of distributors, and the desirability of unbundling storage, transportation and load-balancing services.

To date, most direct sales to Manitoba end-users have been arranged as buy/sells because transportation service only recently became available on the province's two distribution systems.

The Manitoba government has amended the *Public Utilities Board Act* to give the Manitoba Public Utilities Board jurisdiction over gas brokers operating in that province. The question of unbundling rates for distributor services has not yet been addressed in Manitoba.

The OEB has made a number of decisions with respect to the appropriate role of gas brokers in Ontario. In a preliminary decision released on 23 March 1987 the OEB found that "*brokers should be allowed to contract directly with the Ontario LDCs. It is only in this manner that open access to T-service can be achieved so that market-responsive gas prices can be broadly obtained*".[2]

In a final report, released on 9 May 1988, the OEB reiterated its support for the active participation of brokers, noting that "to be "competitive" a marketplace requires, among other things, many buyers and many sellers. In the marketplace for gas, brokers will be part of the "many sellers", either acting as principals in the sale of gas, or as agents for others."[3]

Accordingly, the OEB recommended that the government of Ontario pass the necessary legislation which would simplify the process of brokers entering and operating in the Ontario market.

The OEB has also stated that it is supportive of a complete separation of distributors' transportation and gas sales functions. In the hearing on the appropriate role of gas brokers in Ontario, the broker representa-

1. The agreements provide for a minimum average Alberta border system gas price of $1.85/GJ.
2 OEB *Decision with Reasons* in the Matter of an Inquiry into Contract Carriage (para 3.25) March 23, 1987
3. OEB *Decision with Reasons* in the matter of a hearing respecting the sale of gas in Ontario by brokers. (para 2.24) 9 May 1988

tives argued that, until such a separation is effected, distributors are in a position of conflict of interest. Distributors desire to market their gas and, to the extent that brokers represent competition to the distributors, there is an incentive for distributors to restrict transportation service to third parties. The distributors argued that they could not compete with brokers on an even footing because brokers would selectively pursue high load factor customers, leaving the distributor to sell to the lower load factor core market customers. In commenting on these arguments, the OEB stated that *"under a full separation of the transportation and gas sales functions of the LDC, the gas sales arm of the LDC, making direct sales, would be able to compete with brokers"*.[1]

The issue of rate unbundling was also addressed at the OEB's hearing on the appropriate role of brokers. In their written testimony, the brokers argued that, by such techniques as grouping end-users with similar needs, they could achieve unique methods of cost saving. In its decision the OEB stated that, *"In order to permit others to sell gas on an equal footing with the LDCs, the Board believes that it must be possible for them to have access to gas, storage, and various types of transportation service in varying amounts, and to repackage them for resale. To do this effectively the intermediate party (the "broker" or marketer) must be able to buy and sell gas and transportation services without unnecessary restrictions."*[2] However, distributors in Ontario have not yet been required to provide unbundled services to end-users.

Quebec has not specifically addressed the question of the appropriate role of brokers nor has it addressed the issue of unbundling rates for separate distributor services.

Security of Supply

At the request of the Ontario Minister of Energy, the OEB recently held a major hearing to inquire into all matters pertaining to the current and future supply needs of natural gas users in Ontario. In calling the hearing, the Minister indicated that the government's primary concerns were security of supply and the availability of competitively priced gas for all end-users. The matters discussed at the hearing included most aspects of supply arrangements for Ontario gas users in the current market environment. Importantly, the hearing addressed the question of appropriate purchasing requirements for the LDCs.

In its interim report, the OEB recommended that all direct purchasers be required to hold contracts for both supply and transportation for a minimum of three years, unless otherwise authorized.[3] This recommendation was largely based on the conclusion that direct purchasers risk supply interruption in the short term due to possible shortfalls in pipeline capacity.

Significantly, the OEB did not recommend that the LDCs be required to enter into long term purchase contracts for their core market customers, as was urged by the Canadian Petroleum Association, TCPL/WGML, and the province of Alberta. Rather, the OEB concluded that each LDC is in the best position to determine its optimal gas purchasing strategy and that no regulatory intervention

1. OEB *Decision with Reasons* in the matter of a hearing respecting the sale of gas in Ontario by brokers. (para 2.26) 9 May 1988
2. ibid. (para 2.20)
3. *Gas Supply, Interim Report* Ontario Energy Board E.B.R.L.G. 32, 19 August 1988.

was required, provided that at least a three-year supply was under contract.

The province of Ontario is currently considering the OEB's recommendations.

The government of Quebec passed new legislation (Bill 12) on 17 June 1988 regarding the regulation of the natural gas industry in that province. Although this new legislation provides that distributors must accommodate direct purchases by end-users in Quebec, it also stipulates that, to be acceptable, direct purchases must offer the same degree of security of supply to the end-user as that offered by the distributor. Further, the Régie is empowered to deny a direct sale if the transaction would have adverse impacts on other users of the distribution system. To date, direct sales to Quebec end-users have been accommodated through buy/sell arrangements on GMi.

In summary, the role of provincial government policies and the role of provincial regulatory agencies has grown in importance since the introduction of direct sales into the interprovincial gas market. All consuming provinces have adopted new measures in the last few years to accommodate direct sales to end-users. However, the terms and conditions of access to local distribution systems are still subject to close regulatory oversight.

3.5 Review of the Market Evidence on Direct Sales and Prices

An important measure of the functioning of the domestic natural gas market can be provided by:

- a review of the available evidence on the growth of direct sales;
- an evaluation of prices in domestic markets; and
- a review of prices in domestic markets in comparison with export markets.

The Growth in Direct Sales in Domestic Markets

Direct sales have grown rapidly in B.C. since their introduction in 1986 (Table 3.3). From a base of zero in 1985, direct intra-provincial sales grew to 6.3 petajoules in 1986 and to 22.5 petajoules in 1987. Indications to date are that direct sales will be about 34 petajoules in 1988, representing about 20 percent of total provincial gas consumption.

Table 3.3
Direct Sales in Intra-Provincial Markets
(petajoules)

	1985	1986	1987	1988
British Columbia[1]	0	6.3	22.5	33.5
Alberta[2]	N/A	N/A	277.0	325.0
Saskatchewan	0	0	3.4	21.8

1. Based on data provided to the Board by Westcoast, 2 June 1988.
2. Data prior to 1987 are not available.

In Alberta, the situation is different because direct sales to industrial customers have been a traditional feature of the provincial market. Direct sales have been growing slowly recently and are expected to reach about 325 petajoules this year, close to 60 percent of total Alberta consumption.

Saskatchewan opened its market to direct sales in late 1987. All consumers, including

distribution companies, are now free to purchase gas directly from producers on mutually acceptable terms and conditions. The only constraint is that, for some unspecified length of time, end-users entering into direct sales arrangements must continue to purchase at least 35 percent of their gas requirements from Provincial Gas Limited.[1] Direct sales of Saskatchewan gas within the province have increased from zero in 1986 to an expected 22 petajoules in 1988, representing about 30 percent of total Saskatchewan gas consumption.

There has also been rapid growth of direct sales in the Canadian market served by TCPL east of the Alberta border over the last three years.

Table 3.4
TCPL Domestic Gas Sales and Transportation Service Deliveries Contract Years Ending 31 October (petajoules/year)

	1985	1986	1987	1988 (Est)
TCPL System Gas Deliveries				
To LDCs	–	741	262	265
To End-users*	–	166	511	530
Total TCPL Sales	901	907	773	795
Transportation (Non-System) Gas Deliveries				
For End-users	4	27	119	125
For Distributors	53	72	94	105
Total Transportation	57	99	213	230
Total Domestic Deliveries	958	1006	986	1025

* Includes sales via WGML's distributor fund, customer specific fund, CMPs and, in 1988, SGRs.

Direct sales of non-system gas to end-users served by the TCPL system have increased from a mere 4 petajoules in the 1984/85 gas year to an estimated 125 petajoules in the 1987/88 gas year. Over the same three-year period, total transportation service increased from 57 petajoules to an estimated 230 petajoules. This represented an increase from 6 percent to almost 23 percent of total gas sales off the TCPL system in the domestic market east of Alberta. Further, as there was only modest growth in overall sales over this period, the growth in non-system gas sales came largely at the expense of system gas sales.

Based on preliminary estimates, it appears that the growth in direct sales of non-system gas is slowing in the current gas year while system gas sales are expected to increase, thereby at least temporarily abating the erosion of system gas producers' market share. This increase in both system and non-system gas sales is possible due to an expected overall increase in domestic gas consumption (see Section 4.1 for a discussion of demand growth).

The growth in direct sales is indicative of a healthy competitive environment in the industrial sector of the market. However, very few of these new direct sales have been made to residential or small commercial customers. One of the reasons for the reduction in the rate of growth of direct sales in the current year is that large industrial gas users have taken full advantage of the availability of competitively priced direct sales and this market is essentially saturated.

1. This requirement was maintained to provide some protection to Provincial Gas Limited against the possibility of it failing to meet its minimum take obligations under its gas purchase contracts with Saskatchewan producers.

Residential and small commercial users served by the TCPL system have not yet benefitted from the introduction of direct sales to the same extent as industrial users.

Domestic Gas Pricing

An indicator of the degree to which all Canadian end-users are benefitting from greater competition in the domestic market could be provided by a comparison of Alberta border prices paid by industrial and residential customers in central Canadian markets. It is difficult, however, to obtain such information because prices in privately negotiated contracts are considered proprietary information.

As discussed on pages 25-27, since 1 November 1986 domestic prices for most Canadian gas users served by the TCPL system have been set under agreements between WGML and the major LDCs. Under these agreements, one price has generally been set for "core" market custoners, while industrial users have received discounts off this price under WGML's competitive marketing programs (CMPs) and, more recently, under system gas resales (SGRs). These discount prices appear to have ranged down to at least the $1.30/GJ level.

The result of this pricing system has been a highly stratified "streaming" of system gas to end-users. The largest volume customers have received the lowest prices while progressively higher prices have been charged to smaller users who have little or no flexibility to switch to an alternate fuel supply in the short run.

Comparison of Domestic and Export Prices

If the Canadian and U.S. gas markets were truly integrated, competition between Alberta producers would tend to equalize wellhead prices for gas sold into the two markets on similar terms and conditions.[1] If, for example, netbacks from selling Alberta gas in the eastern Canadian market were higher than netbacks from exports, producers in Alberta would prefer to sell into the Canadian market. The resulting competition for this more lucrative market would place downward pressure on prices until netbacks on eastern Canadian sales were roughly equivalent to those available on sales into U.S. markets.[2]

One would never expect to observe exactly equivalent prices, even in a perfectly functioning competitive market, due to such factors as differences in the dates on which contracts were signed and differences between the exact terms and conditions of each contract. Further, the need for fixed long distance pipelines prevents the free flow of natural gas from all supply sources to all market centres. The rigidities created by transportation logistics allow for the persistence of price differentials between markets that would not occur, for example, in the oil market. Nonetheless, as the barriers to both interprovincial and international trade are lowered, one would expect to observe a nar-

1. The final price charged to each end-user would of course reflect differences in transmission, storage and distribution costs. The above argument refers only to the gas component of the final sales price.
2. The above argument applies to wellhead prices within a particular producing region, such as Alberta. However, wellhead prices between two different producing regions, such as Alberta and Texas, could differ due to differences in transportation costs to major consuming centres. For example, in a competitive market the market prices of both Texas and Alberta gas sold into the U.S. mid-west would be approximately equal. However, wellhead prices in Texas could be higher than in Alberta because producers in Texas face lower gas transportation costs to the U.S. mid-west.

rowing of any wellhead price differentials for gas sold from any particular producing region.

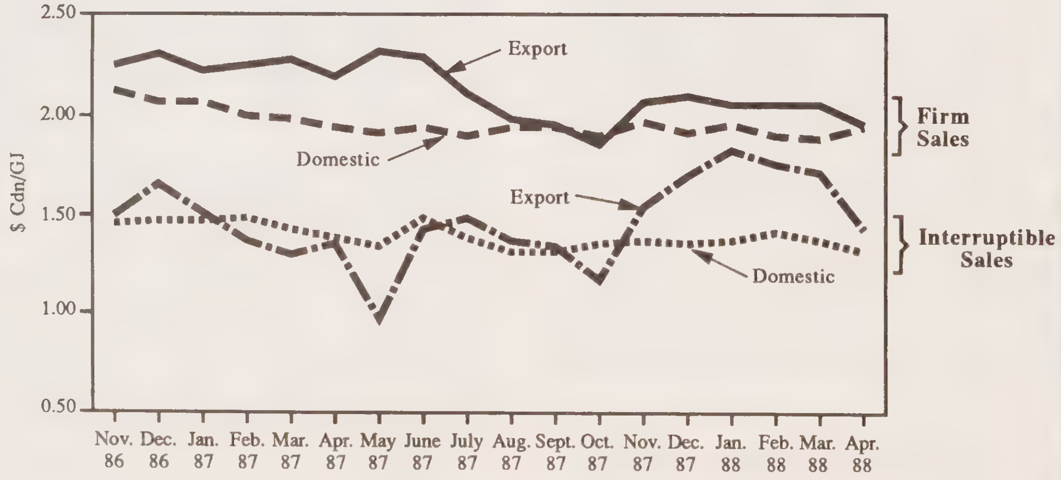
In light of the above comments, a useful secondary measure of the degree of competition in the Canadian market is provided by a comparison of domestic and export prices.

Export prices of Alberta gas sold under long term contracts were consistently above domestic prices until about September 1987. Recently, domestic and export prices of Alberta gas sales have been converging (Figure 3.3).

The data indicate that for sales of Alberta gas, spot prices of exports are more volatile than spot prices of domestic sales. Whereas average domestic prices on interruptible sales varied within a narrow band between \$1.30/GJ to \$1.50/GJ, export prices on interruptible sales fell as low as \$0.98/GJ in May 1987 and went as high as \$1.83/GJ in January 1988. On average, domestic prices were slightly lower than export prices over the data period.

The data for British Columbia indicate that average domestic prices of long term firm sales have been substantially below export prices of B.C. gas (not shown). However, this was due to the low rates of take under the long term gas sales contract between Westcoast and Northwest Pipeline Corporation (Northwest), its principal export

Figure 3.3
Average Domestic and Export Prices
Alberta Border*



* See Appendix D for footnotes.

customer. The average sales price increases when purchases fall because of the fixed demand charges which Northwest has been required to pay to Westcoast.

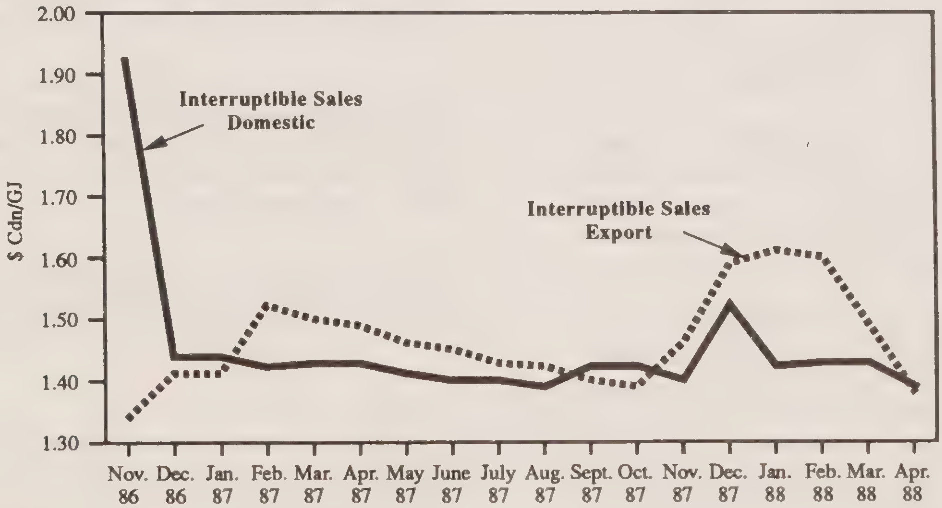
Domestic and export prices for interruptible sales of B.C. gas have been remarkably close on average (Figure 3.4). With the exception of November 1986, when domestic prices were $.56/GJ higher than export prices, the data indicate that export prices averaged about $0.05/GJ more than domestic prices.

On the basis of the foregoing evidence, it would appear that Canadian end-users have generally had access to Canadian gas on terms at least as favourable as export customers. However, the data as presented are highly aggregated and do not provide a comparison of export prices versus domestic prices by customer class.

During the observed data period, some impediments to the free flow of Canadian gas to U.S. markets remained, of which the most important was the lack of access to transportation service on some U.S. pipelines. However, more U.S. pipelines have recently opened up their systems to accept direct sales by all shippers and access to transportation service on U.S. pipeline systems should not be a major barrier to Canadian exports over the next few years. In the near term, limitations on pipeline capacity may be the major constraint on increased exports.

Figure 3.4

Average Domestic and Export Prices British Columbia Border*



* See Appendix D for footnotes.

Currently, with the exception of deliveries via the Great Lakes transmission system, pipeline capacity to import gas into Canada is limited to about 25 petajoules per year. This limitation reduces the scope for price competition in eastern Canadian markets.

In a fully competitive integrated North American market, Canadian users would be free to purchase gas from the supplier of their choice, including U.S. suppliers. As matters now stand, if GMi, for example, were not satisfied with contract offers from Canadian suppliers, it would not have the practical alternative of requesting bids from U.S. producers. Although Union Gas increased its imports from the U.S. during the 1986/87 contract year, it is one of the few Canadian distributors with direct access to U.S. supplies.[1]

To conclude, the market evidence on domestic and export prices to date suggests that Canadians have been able, on average, to obtain gas at prices equal to or lower than those available to export customers.

3.6 Summary - Assessment of the Functioning of the Market

In light of the review provided in this chapter, a number of conclusions can be drawn about the functioning of the domestic natural gas market since the implementation of the 1985 Gas Agreement.

Substantial progress has been made towards the development of a competitive domestic gas market. There has been intense competition for the industrial market between WGML and direct sellers as a group, and between individual direct sellers. Saskatchewan producers have entered the interprovincial market for the first time and, although the volumes are small relative to total interprovincial sales, they are providing an important new source of competition to Alberta gas sales. The reduction of up to $1.60/GJ in gas prices to industrial end-users in the last two years is evidence of the degree of competition between producers for the industrial market.

At the same time, gas prices to most other gas consumers have only been reduced by about $0.60/GJ since November 1986. Thus, although "core market" users have benefitted from lower prices, the price reductions have not been as great as might be expected in light of the large excess of supply which has overhung the market.

The fact that prices to some domestic end-users have remained relatively high is in large measure a result of:

- the inability of distributors to purchase gas from the supply source of their choice because the Board has not permitted access to TCPL for gas volumes which would displace purchases made under existing long term contracts with TCPL;
- the Alberta government's policy on removal permits which has constrained the ability of some end-users to freely enter into direct purchase contracts with Alberta producers; and
- the ability of WGML/TCPL to maintain the market share of system gas sales due to their special market position, e.g. the

1. The Board recently approved an application by St. Clair Pipelines Ltd. to construct a pipeline under the St. Clair river which will allow Union Gas Ltd. (Union) and other gas buyers to import additional gas. The initial design capacity of this pipeline is approximately 80 petajoules per year.

ability to take advantage of buy/sell arrangements which utilize transportation capacity associated with TCPL's existing sales contracts with LDCs.

The 1985 Gas Agreement envisaged the development of a competitive domestic market for natural gas. Much of the controversy in the last two years has revolved around different interpretations of what constitutes an appropriate competitive market for interprovincial sales to core-market customers.

On the producer-shipper side, TCPL, the Canadian Petroleum Association and the government of Alberta are of the view that core-market customers should be required to purchase gas under long term firm contracts. Further, it is their view that it is appropriate that core-market customers pay higher prices for their gas supplies to reflect the greater security provided by long term contracts.

On the consuming side, many small-volume end-users and LDCs believe that they should be permitted to purchase gas on a short term basis and that the price of such gas should be competitive with sales prices to industrial end-users.

In summary, actions by governments, regulators and commercial interests following the 1985 Gas Agreement have resulted in the creation of a highly competitive interprovincial market for large volume industrial gas users. Given the excess supply hanging over the market, the move from regulated pricing to privately-negotiated pricing has worked in favour of consumer interests. Prices to industrial users have fallen steeply, largely due to stiff competition between gas sellers in the face of excess supply. Gas prices to small-volume commercial, institutional and residential end-users have also fallen, but not to the extent one would expect to see in a fully competitive market. On average, domestic gas consumers have had access to Canadian gas at prices equal to or below those available to export customers.

Chapter 4

Canadian Gas Supply, Demand and Prices: A Short Term Assessment

There has been a large surplus of productive capacity in the North American gas market throughout the 1980s. (Figures 4.1 and 4.2).

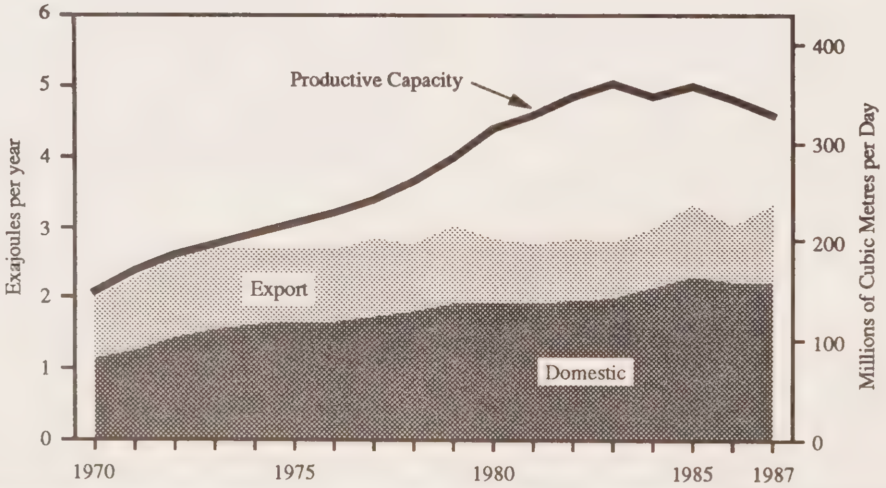
As discussed in Chapter 2, rapid price increases and expectations of rising export and domestic demand encouraged gas exploration activity in the 1970s. This led to large increases in productive capacity in Canada and halted the previous decline in productive capacity in the United States. Subsequently, gas demand fell in the United States and stopped growing in Canada. Increasing supply combined with falling demand led to the development of excess supply, commonly referred to as the gas bubble.

Gas prices in both Canada and the United States were tightly regulated throughout most of the 1970s and early 1980s. High regulated prices helped induce and sustain the bubble because prices were not allowed to fall to clear the market.

Since 1985, gas prices have increasingly been set by market forces in both Canada and the United States. Price deregulation in the face of excess supply led to a rapid decline in North American gas prices. Falling prices have discouraged gas exploration and encouraged gas demand; consequently, the excess supply has been declining in recent years.

Figure 4.1

Productive Capacity and Demand Canada



This chapter provides an assessment of the outlook for the demand for and supply of Canadian natural gas over the next two years. Section 4.1 reviews recent developments and the short term outlook for domestic demand and Section 4.2 reviews the outlook for Canadian exports. Section 4.3 discusses recent developments and the short term outlook for Canadian gas supply and section 4.4 provides a summary assessment of the short term outlook for the supply/demand balance.

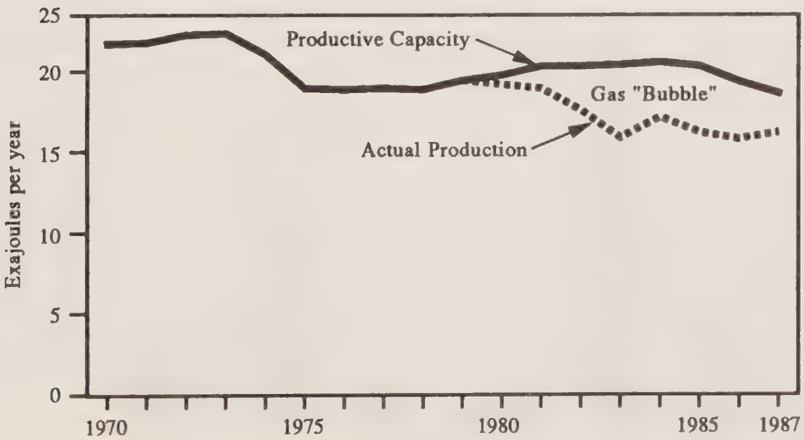
4.1 Canadian Natural Gas Demand

About 50 percent of the natural gas used in Canada is consumed by the residential and commercial sectors, primarily for space heating. Another 40 percent is used as boiler fuel in industrial production processes and about 8 percent is used as feedstock in the production of petrochemicals such as ammonia and methanol. A small proportion, about 3 percent, is consumed as fuel for electricity generation, mostly in Alberta.

Regionally, Ontario is the largest consumer of natural gas, accounting for nearly 40 percent of Canadian consumption, followed by Alberta which accounts for about 30 percent. Quebec, Manitoba, Saskatchewan and British Columbia together account for the remaining 30 percent. A small amount of natural gas, produced from wells in the

Figure 4.2

Productive Capacity and Demand*
United States



*Source: "Planning and Analysis Issues", American Gas Association, 13 July 1987.

Moncton area, is consumed in New Brunswick. No natural gas is used in Nova Scotia, Prince Edward Island, or Newfoundland (Figure 4.3).

Recent Developments in Demand

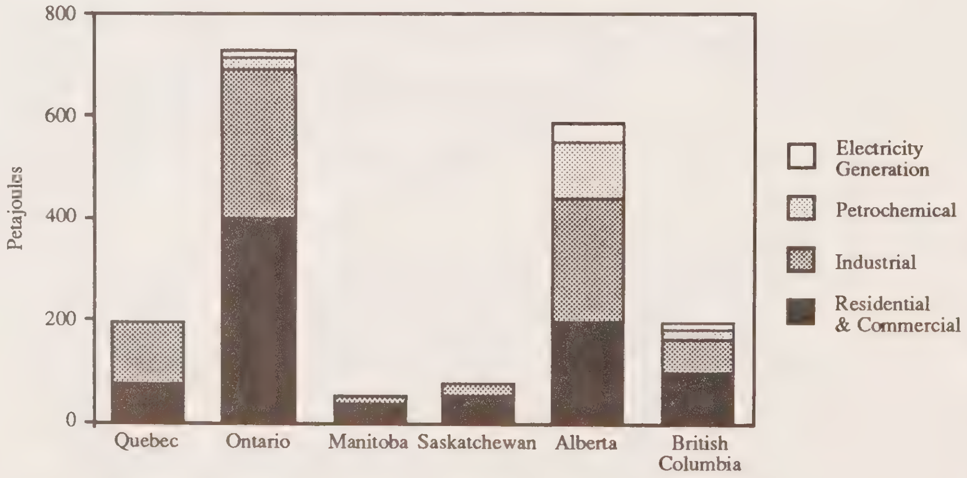
Natural gas demand growth in Canada was rapid in the 1960s and early 1970s; demand growth then slowed from the mid-1970s to 1982 and then increased rapidly from 1983 to 1985. The share of natural gas in total Canadian energy demand peaked at close to 24 percent in 1985.

Since 1985 natural gas use in Canada has declined, notwithstanding continued growth in total primary energy use, and its share of the market dropped from the peak of 24 percent in 1985 to about 22.5 percent in 1987. The decline in natural gas demand occurred primarily due to a fall in demand in the residential and commercial sectors; industrial use of gas remained virtually constant and gas used in electricity generation increased modestly.

The decline in gas use among households and commercial institutions is attributable to a number of factors. In 1985 the federal government ended a subsidy program which had paid part of the costs to homeowners of switching from oil to natural gas. The subsequent fall in oil prices in early 1986 then removed much of the remaining incentive to switch to natural gas for space heating.

Figure 4.3

Natural Gas Demand in Canada Consumption by Sector and Region (1987)*



* Data based on estimates by NEB staff.

The weather, however, was the major factor behind low residential and commercial gas use in 1986 and 1987. In 1985, average temperatures in Canada were close to normal but in 1986 and 1987 temperatures were 4 and 10 percent warmer than normal. Although weather patterns varied widely across Canada, the overall effect was a sharp reduction in gas demand for space heating in the last two years.

In the last 2 years, industrial gas demand has been steady, rising by about 1 percent in 1986 and declining by a similar amount in 1987. Industrial demand has been influenced by offsetting factors:

- Industrial output increased by almost 2 percent in 1986 and by 4 percent in 1987, thereby stimulating industrial demand for gas. However, growth in output was not spread equally across regions. While eastern Canada experienced relatively strong growth, western Canada, particularly Alberta which accounts for one-third of industrial gas demand in Canada, experienced a decline in industrial activity in 1986 and 1987.

- Natural gas temporarily lost its competitive advantage over fuel oil in eastern Canada. When oil prices collapsed in 1986, gas prices did not fall quickly enough to prevent some industrial users from switching away from natural gas in late 1986 and early 1987.

From 1985 to 1987, gas demand for petrochemical feedstock changed very little, although poor demand for methanol contributed to a slight reduction in natural gas use in 1986.

The amount of gas used for electricity production has changed very little over the last 3 years and most of the observed variations have been the result of changes in peak electricity demand in Alberta.

The Short Term Outlook for Natural Gas Demand

The weather is the dominant factor in short run variations in residential and commercial natural gas use; industrial activity and relative fuel prices are the major influences on industrial and petrochemical demand.[1]

Given the likely continuance of excess supply over the next two years, prices of gas sold to domestic industrial gas users under short term firm contracts should remain low. As excess productive capacity diminishes, it is possible that there will be some upward movement in prices thereafter.

Prices for spot sales of gas will fluctuate according to prevailing market conditions. For example, spot sale prices typically increase in the winter months when demand is high and fall again in the summer months.

As discussed on page 26, prices to most domestic residential and small commercial users have been determined in recent agree-

1. In the short run, the importance of relative fuel prices is limited. In Canada, although many industrial gas users have the capability to switch from natural gas to heavy fuel oil or electricity, few can do so for a sustained period. Without additional investment in equipment, we estimate that only 10 percent of existing industrial gas use in Ontario and Quebec (about 40 petajoules in 1986) could be switched from gas to heavy fuel oil in the short term. However, if a 30 percent price differential persisted for a longer period, say 3 years, we estimate that about 20-30 percent of eastern Canadian gas consumption could be lost to other energy sources.

ments between WGML and the major distribution companies. The new agreements provide for a pricing agreement which effectively yields an Alberta border price of $2.20/GJ to all "core" market customers in Manitoba, Ontario and Quebec for the next two years and is subject to renegotiation thereafter (this excludes customers in Union's franchise area because, at the time of writing, Union had not yet come to terms with WGML).

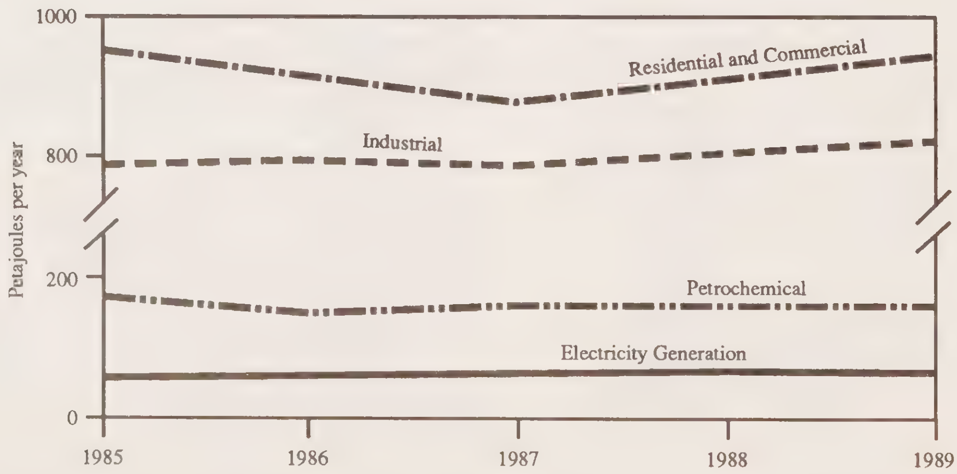
For 1988, our estimate of residential and commercial gas demand is based on the assumption that temperatures in Canada will be about 4 percent warmer than normal. This estimate incorporates actual degree-data through July 1988 and assumes normal weather over the balance of the year. Year over year it represents a cooling of some 6 percent relative to 1987. For 1989, we assume normal temperatures in our forecast, implying a further cooling of some 4 percent relative to 1988.

Given normal temperatures, demand in the residential and commercial sectors may be expected to grow by close to 4 percent in 1988 and by a further 4 percent in 1989. The increase would be much greater than average in western Canada where temperatures showed the largest deviations above normal in 1987.

Assuming that natural gas remains competitive with other fuels, and given a continua-

Figure 4.4

Natural Gas Demand in Canada
Recent Performance and Short-Term Outlook*



* Historical data, 1985-1986 based on Statistics Canada information; data for 1987-1989 based on estimates by NEB staff.

tion of strong economic growth through the remainder of this year, we expect industrial natural gas use to grow by about 2 percent in 1988.

In 1989, a more slowly growing economy may tend to dampen growth in energy and natural gas use in industry. However, the Hydro Quebec industrial surplus electricity program is being phased out at the end of this year. This should generate an appreciable increase in natural gas demand in Quebec in 1989 as electricity users switch to gas. We also expect some expansion in the production of bitumen in Alberta in 1989 which will result in increased demand for natural gas to produce steam for use in the bitumen recovery process. Taken together, these factors are expected to generate increases in industrial gas demand of about 3 percent in 1989.

We do not expect any change in the number of petrochemical plants in operation in the next two years, nor do we expect the level of capacity utilization of existing plants to change appreciably. Therefore, we expect natural gas use by petrochemical plants to remain at 1987 levels.

It is difficult to forecast the demand for gas for electricity generation because it is difficult to forecast peak electricity requirements. Based on our best estimates of peak requirements, we expect some small increase in gas use for electricity generation in 1988 and 1989.

In summary, we expect natural gas demand in Canada to resume its growth in 1988 and 1989 at a rate of about 3.3 percent per year as a result of broadly based growth in the major consuming sectors (Figure 4.4 and Table 4.1).

Table 4.1
Primary Demand for Natural Gas
Canada

	PJ	% Increase	% Share of Primary Energy Held by Gas
1985	2117		24.2
1986	2064	-2.5	23.4
1987	2046	-0.9	22.4
1988	2114	3.3	22.8
1989	2184	3.3	23.2

4.2 Recent Performance and Short Term Outlook for Canadian Exports

Canada's exports to the U.S. built up steadily during the late 1960s and early 1970s, reaching a peak of just over 1 exajoule in 1973. This represented 4.7 percent of the total U.S. market. Both export volumes and the market share of Canadian exports remained fairly stable until 1980. Exports then declined sharply during the first half of the 1980s, reaching a low of about 770 petajoules in 1983. Canada's share of the U.S. market remained above 4 percent because total U.S. demand for gas had also declined.

In an effort to preserve its share of a shrinking U.S. gas market, in July 1983 Canada amended its uniform border price policy for exported gas. Under the new volume-related incentive price (VRIP) policy, price reductions were allowed for sales above 50 percent of annual licensed quantities.

In response to the growing gas surplus in the U.S. and the new U.S. import policy guidelines, Canada again changed its export policy in November 1984. The new policy

allowed for buyer/seller negotiated export prices, subject to a number of criteria, the most important of which was that export prices could not be lower than the Toronto wholesale price for gas.

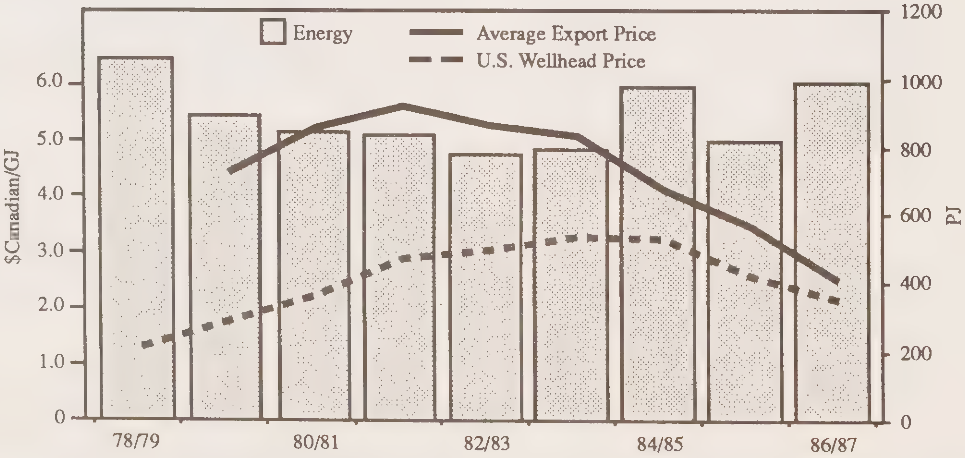
Exporters were given further flexibility in October 1985 with the removal of volume restrictions on short term export orders and the replacement of the Toronto floor price with regional floor price tests. Exporters were initially required to demonstrate that proposed exports satisfied the pricing criteria prior to receiving export approval. In November 1986, this system was replaced by after-the-fact monitoring of export prices (Figure 4.5).

While export policy was changing, export arrangements were also being modified to reflect new market realities in the United States. For example,

- flexible pricing based on alternative fuel prices with regular price reviews was introduced to long term contracts;
- multi-tier contracts which permitted the sale of some volumes into the spot market under a system of monthly price review were introduced; and
- marketing efforts were redirected away from system sales to pipelines towards direct sales to distribution utilities.

Figure 4.5

Export Volumes vs Average Export Border Price and Average U.S. Wellhead Price

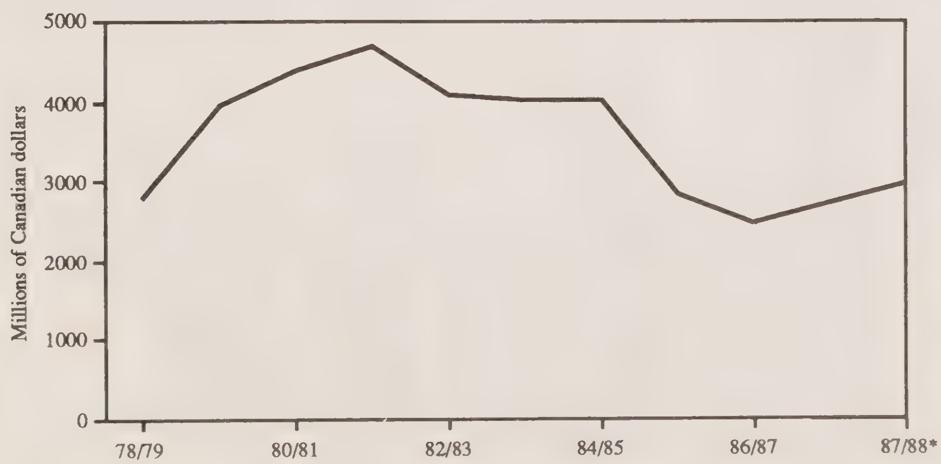


Export volumes have responded positively to the changes in policy and export arrangements and have returned to the levels of the 1970s. While exports dipped in 1985-86, this was largely a result of take-or-pay problems between U.S. pipelines and their producers. U.S. producers were often given preference over Canadian producers because many U.S. pipelines had minimum take obligations to their U.S. producers but not to Canadian producers.

Although export volumes have been increasing, total revenue from exports has been declining due to the large decrease in average export prices (Figure 4.6).

In the U.S., interstate pipelines are increasingly acting as transporters of gas to accommodate direct purchases by LDCs and other end-users. This is reflected in the changing structure of export sales; larger volumes are being sold directly to LDCs and to end-users via brokers (Figure 4.7). Increasing volumes of exports are also being sold in the short term spot market (Figure 4.8). However, long term sales are still the backbone of Canada's export trade.

Figure 4.6
Total Export Revenue



* Preliminary estimate.

Figure 4.7

Structure of Export Sales

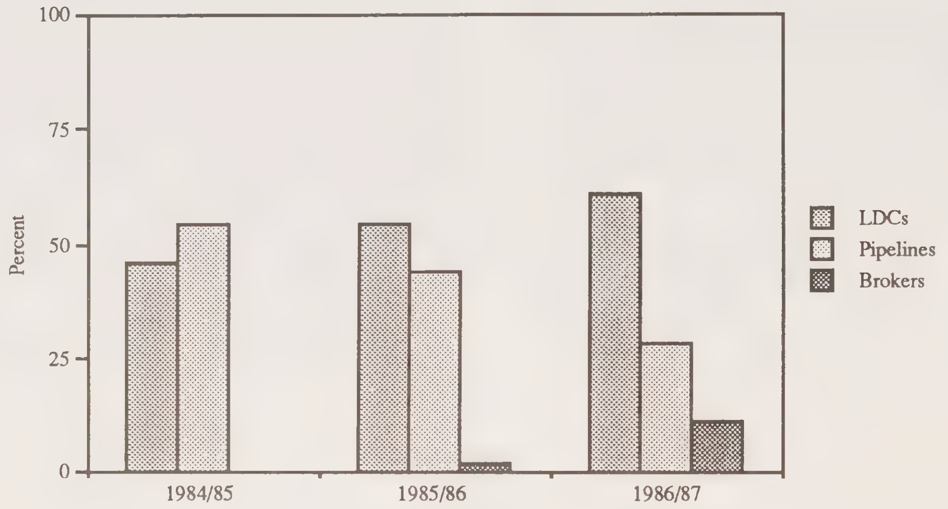
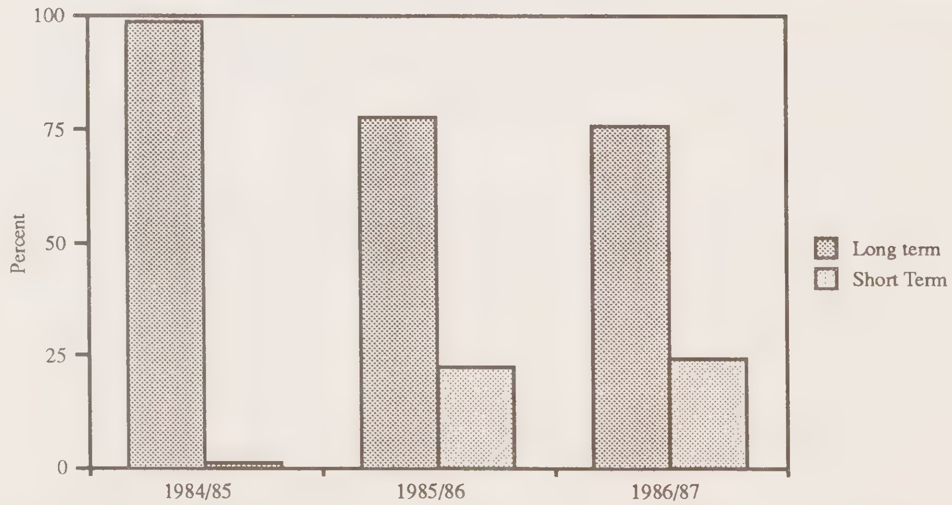


Figure 4.8

Structure of Export Arrangements



Export Outlook

Exports are forecast to grow by 22 percent and 9 percent respectively in 1988 and 1989, reaching a level of about 1.4 exajoules in 1989 (Figure 4.9).

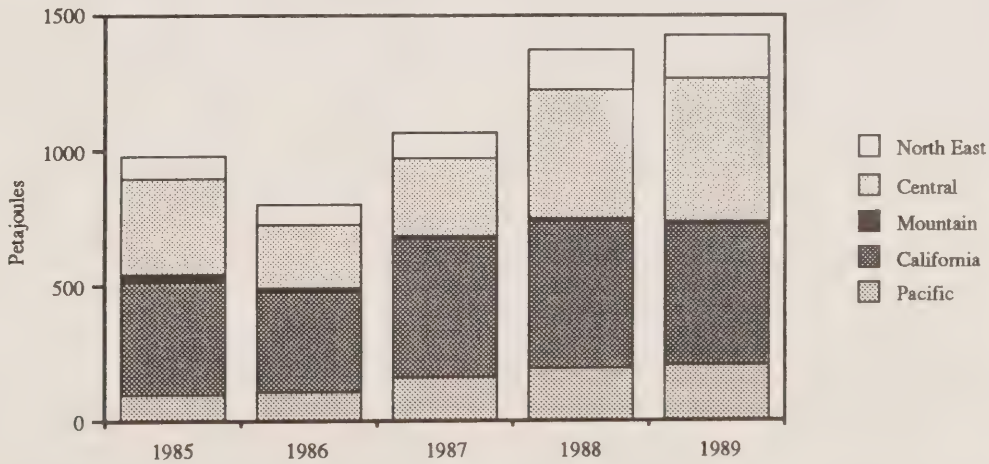
The current and anticipated improvement in gas exports is a result of a competitive export pricing policy, a modest resurgence in the total demand for natural gas in the United States and improved access to U.S. pipelines brought about by FERC Orders 436/500. (See Appendix B for a list of pipelines operating under open access.)

While export sales have made large gains of late, they still account for about only 7 percent of total U.S. gas consumption.

Regionally, Canada supplies about one-half of the gas consumed in the Pacific Northwest and about one-quarter of California's consumption, including about 50 percent of northern California's. In the mountain, central and northeast regions, Canada accounts for less than 4 percent of the gas supply. Canada's market share has grown steadily over the past twenty years in the California and northeast markets, remained relatively stable in the central region but has declined significantly in the mountain and Pacific Northwest regions where low cost coal and heavy fuel oil have provided stiff competition.

Figure 4.9

Natural Gas Exports by region and market



California, Canada's largest market, accounted for nearly one-half of total exports in 1987 and was responsible for 52 percent of the increase in total exports in 1987 over 1986 (Figure 4.10). Most of California's increase can be attributed to higher sales by Alberta & Southern to Pacific Gas & Electric in northern California. Sales to SoCal Gas in southern California have been at 100 percent of contract levels for the past three years.

Approximately two-thirds of the export growth in the 1988-89 period is expected to occur in the central U.S. market region.

Figure 4.10

Canadian Export Flows to U.S. Regional Natural Gas Markets

Export Points

1 Huntingdon, B.C.	4 Aden, Alta.	7 Sprague, Man.	10 Niagara Falls, Ont.
2 Kingsgate, B.C.	5 Monchy, Sask.	8 Fort Frances, Ont.	11 Cornwall, Ont.
3 Cardston, Alta.	6 Emerson, Man.	9 Windsor, Ont.	12 Philipsburg, Que.

Pipeline importers in this region have taken little Canadian gas in recent years due to domestic take-or-pay obligations but they are now resuming purchases of Canadian gas. Canadian sellers are also enjoying improved access to U.S. markets through U.S. pipelines which have recently become open access transporters of gas.

Sales to the Pacific Northwest region are also expected to benefit from improved U.S. pipeline access. Sales into the northeast U.S., which are presently constrained by pipeline capacity, will benefit from a planned 40 percent increase in capacity on TCPL's Niagara line for the 1988-89 contract year.

While total exports are increasing, long term exports have been flowing at rates well below levels authorized by NEB licences. Our forecast implies that long term exports will be about 55 percent of the authorized level in 1989.

4.3 Reserves and Productive Capacity

Remaining reserves of natural gas in Canada are estimated to have declined by roughly 6 percent from 77.3 exajoules at the end of 1985 to 72.3 exajoules at the end of 1987. Production during this period was about 3.2 exajoules per year, outpacing annual additions to reserves which averaged only slightly more than 1 exajoule. The annual production and reserves additions estimates are shown in Table 4.2, together with projections for 1988 and 1989.

During the 1985-87 period, the rate of new discoveries was essentially constant at about 0.6 exajoules per year.[1] This rate, which is well below those of the peak drilling years during the late 1970s and early 1980s, is a result of the comparatively low levels of exploratory drilling undertaken in recent years. The most notable discovery during this period was the Caroline field in Alberta, which contains marketable gas reserves estimated to be about 0.6 exajoules.

Revisions and extensions to existing reserves declined substantially from 1.3 exajoules in 1985 to a negative value in 1987. This was largely due to downward revisions to the estimates of reserves assigned to small Alberta pools[2]. To date, we have reduced the reserves of the small producing pools by about 3 exajoules. We expect to include further reductions for the non-producing pools in our final 1987 estimates and in those for 1988. By 1989, with these downward adjustments completed, reserves additions from revisions and extensions will likely return to levels more in line with those experienced historically.

Reliable estimates of the reserves of small pools are important because these pools may well provide a major portion of future gas supply. However, because 70 percent of these pools have never produced, and because they generally contain only one well, reliable estimates are difficult to achieve. Over the past decade, the proportion of remaining reserves in smaller-sized pools has increased as a result of the large number of small pool discoveries and the depletion of the larger pools.

In Alberta, some 35 percent of the province's remaining reserves are in pools which originally contained 10 petajoules or less. Reserves remaining in these small pools average about 1 petajoule per pool. These pools are, on average, only about 20 percent

1. Based on initial year bookings.
2. We define small pools as pools with reserves before production of 10 petajoules or less.

depleted whereas the larger pools, which have accounted for approximately three-quarters of all reserves found to date, are nearly 50 percent depleted.

Outlook for Reserves Additions

Little change is anticipated in the level of gas-directed exploratory drilling over the next two years because of the current supply surplus. Therefore, discovery rates are projected to be comparable to those of the preceding three years.

Natural gas production is expected to rise to 3.6 exajoules and 3.8 exajoules in 1988 and 1989 respectively, mainly due to anticipated higher exports.

The net result of our forecasts of reserves additions and production is that remaining established reserves could fall a further 6 percent to a level of about 68 exajoules by the end of 1989 (Table 4.2).

Table 4.2
Remaining Established Reserves of Marketable Natural Gas In Conventional Areas[1]
(exajoules)

	Remaining Reserves Beginning of year	Additions			Annual Production	Remaining Reserves Year-End
		Discoveries	Revisions & Extensions	Total		
1985	78.6	0.6	1.3	1.9	3.2	77.3
1986[2]	77.3	0.5	0.8	1.3	3.1	75.3
1987[3]	75.3	0.5	-0.3	0.2	3.2	72.3
Forecast						
1988	72.3	0.6	-0.2	0.4	3.6	69.1
1989	69.1	0.6	1.6	2.2	3.8	67.5

1. Based on estimates by Board staff.
2. 1986 numbers do not balance because of an adjustment to Ontario's cumulative production
3. Preliminary

Reserves To Production Ratio

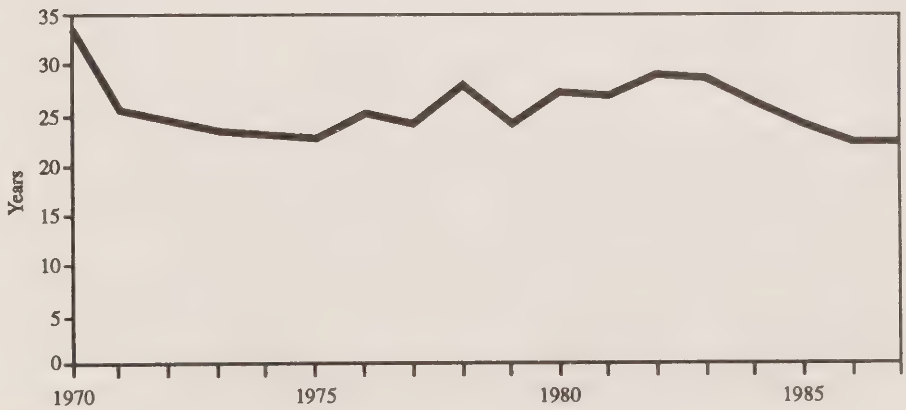
The reserves to production ratio is the ratio of currently remaining established reserves to the current annual rate of production.

Following an initial period of decline prior to 1971, the reserves to production ratio for western Canadian natural gas stabilized around 25 until 1979, as both reserves and production levels increased at approximately the same rate. In the early 1980s, continued increases in reserves, combined with falling overall demand, resulted in the ratio moving upward to a maximum of about 29 in 1982 and 1983. Since then the ratio has fallen, reflecting declining reserves as well as, in 1987, sharply increased production. The reserves to production ratio for 1987 is estimated at 23. The provincial ratios cover a relatively narrow range: 27 for British Columbia; 23 for Alberta; and 24 for Saskatchewan.

Certain reserves, for example reserves deferred for conservation reasons and reserves currently uneconomic to develop, are not immediately available to meet demand. Taking into account the non-availability of those reserves in the short term, we estimate that full utilization of currently available productive capacity would result in a reserves-to-production ratio of about 14 for the western provinces.

Figure 4.11

Natural Gas Remaining Reserves/Production Western Canada



Productive Capacity

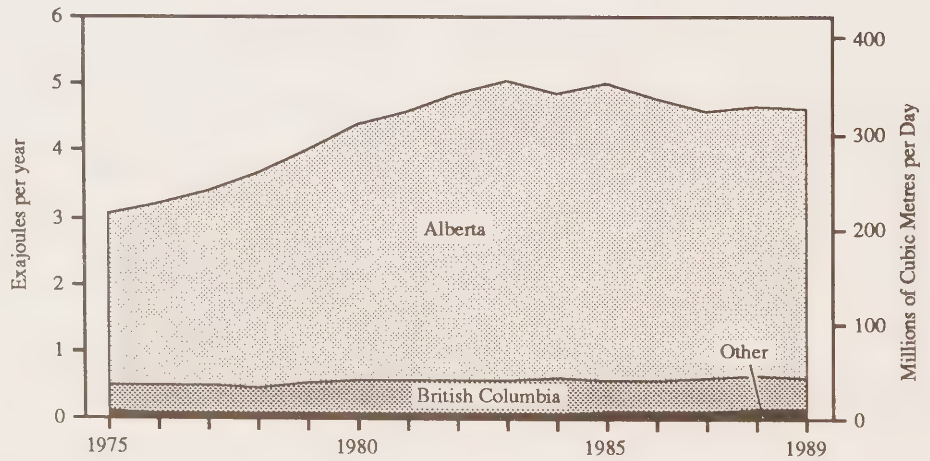
Productive capacity is an estimate of the available production at any particular time.[1] Almost 90 percent of Canadian productive capacity is in Alberta, some 10 percent in British Columbia and the remainder in Saskatchewan, the Northern Territories and eastern Canada (Figure 4.12).

Annual productive capacity in Alberta grew rapidly during the late 1970s and early 1980s but has declined slightly since 1983 to its current estimated level of about 3.9 exajoules.

Productive capacity in British Columbia grew steadily until 1973. Subsequently, deliverability problems experienced in the Beaver River field in northern British Columbia resulted in a shortfall in meeting the contractual obligations of Westcoast's customers in the Pacific Northwest region of the United States. Productive capacity continued to decline until the late 1970s when it again began to increase as a result of higher levels of drilling activity. Current annual productive capacity in British Columbia, and the adjacent southern Yukon and Northwest Territories connected to the Westcoast system, is estimated to be about 500 petajoules.

1. A more rigorous definition of productive capacity is provided in the glossary.

Figure 4.12
Productive Capacity Canada



Annual productive capacity in Saskatchewan and eastern Ontario is currently about 100 petajoules.

Our estimates represent the productive capacity immediately available from all connected reserves, plus that which could be made available from both connected and unconnected reserves and from reserves additions within about six months. These estimates include productive capacity from some infill wells which, although we consider them economic on a stand-alone basis, may not be drilled because of an individual producer's particular economic situation. For these reasons, our estimates will be higher than productive capacity immediately available. Further, our projections are not constrained by the gathering and transmission capacity of major pipeline systems such as NOVA and TCPL.

In summary, given our outlook for reserves additions and annual production, we expect Canadian annual productive capacity to remain essentially unchanged for 1988 and 1989.

Natural Gas Imports

Currently, natural gas imports do not play a large part in Canada's supply and demand picture. For the gas contract year ended 31 October 1987, net imports amounted to just over 3 petajoules, about two-tenths of one percent of domestic gas consumption. Gas imports started to increase in November 1987 when almost 2 petajoules were imported. Little gas was imported last winter but volumes returned to the 2 petajoule per month level in March and April. From 1 November 1987 until 31 August 1988, imports totalled about 15 petajoules.

Almost all imports enter the country near Windsor, Ontario and serve the Ontario market. The three main importers are Union Enterprises (a parent company to Union Gas Ltd.), Union Gas Ltd. (Union) and Consumers' Gas. The gas has been sold on a short term interruptible basis at prices related to the U.S. spot market price.

The facilities presently used to import gas near Windsor connect Union's distribution system in Ontario to Panhandle Eastern Pipeline Co., an interstate pipeline with access to diverse gas supplies. The capacity to import gas at Windsor is currently about 2 petajoules per month.

Since the short term nature of the present import arrangements makes forecasting future import levels highly uncertain, we have not incorporated imports into this assessment. However, the Board recently approved an application by St. Clair Pipelines Ltd. to construct a new pipeline under the St. Clair river which, if built, would appreciably increase import capacity. Thus, imports could well become a significant factor in Canada's natural gas supply/demand balance in the near future.

4.5 Assessment of the Near Term Supply/Demand Balance

Canadian natural gas productive capacity is expected to be more than adequate to supply forecast demand for natural gas, including gas exports, over the period of this outlook (Figures 4.13 and 4.14).

On a peak day basis, however, supply capability and demand are rapidly approaching a balance (Figure 4.15).

Figure 4.13

Productive Capacity and Demand
Alberta and East of Alberta

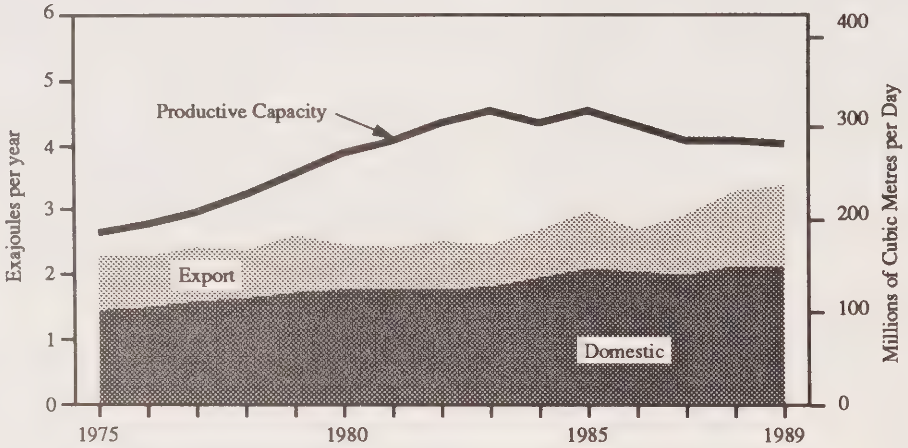


Figure 4.14

Productive Capacity and Demand
British Columbia

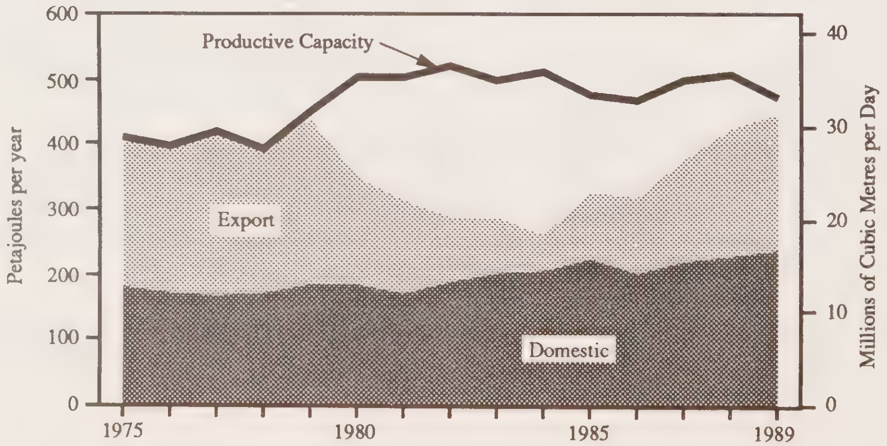
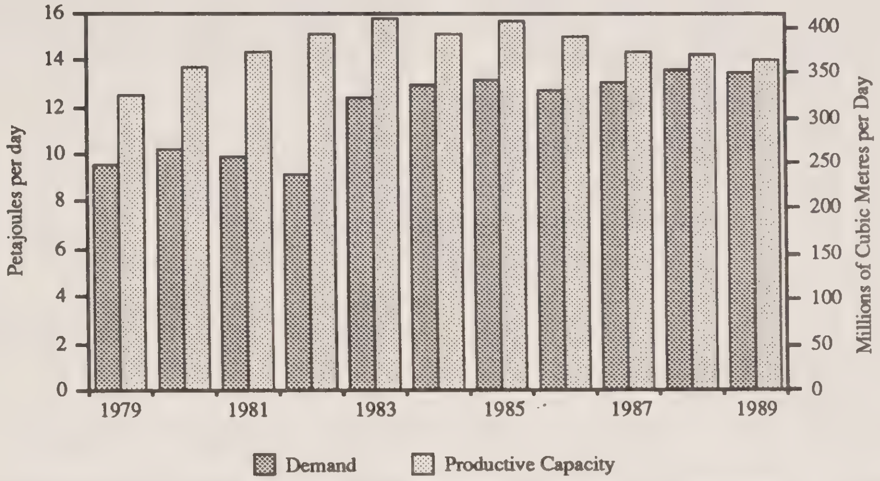


Figure 4.15

Productive Capacity and Demand (Peak Day)



Over the past five years, peak day market demand has averaged some 150 percent of average day demand while supply contracts generally contain peak day provisions ranging from 110 to 133 percent of average day demand. Utilization of productive capacity during peak days is forecast to exceed 90 percent in the next two gas years (Table 4.3).

In summary, productive capacity should be more than sufficient to meet demand over the next two years, although the margin of capacity over demand on peak days has been narrowing.

As discussed in the following chapter, the major constraint on increased sales in the near term will be limited pipeline capacity.

Table 4.3
Forecast of Productive Capacity and Demand[1]
(Petajoules)

	1985	1986	1987	1988	1989
Annual Basis (petajoules/year)					
Productive Capacity	4995	4790	4593	4565	4496
Demand					
- Primary Domestic Demand	2117	2064	2046	2114	2184
- Reprocessing Shrinkage	195	183	199	223	231
- Exports	975	794	1063	1370	1421
	3287	3041	3307	3707	3836
% utilization of productive capacity	66	63	72	81	85
Peak Day Basis (petajoules/day)					
Productive capacity	15.6	15.0	14.4	14.3	14.1
Total Demand	13.1	12.7	13.1	13.5	13.5
% utilization of productive capacity	84	85	91	94	96

1. All figures in this table are calculated at the field plant gate. Peak day productive capacity is calculated from annual data using an average load factor related to the maximum daily rates in producer contracts. Peak day total demand is estimated from peak day pipeline utilization data for the major gas transmission systems in Canada. It is a measure of the peak call on productive capacity rather than a measure of end-user peak day demand.

Chapter **5**

Pipeline Capacity for Domestic and Export Markets

The ability to deliver natural gas to end-users as needed depends not only upon productive capacity but also upon the capacity of the pipeline network and associated storage system. In this chapter, we review the quantities of gas expected to flow on Canadian transmission systems in 1989 to both domestic and export markets and compare these flows to the available pipeline capacity. In addition, we review the role of storage capacity in the gas delivery system and consider the short term need for increased pipeline and storage capacity.

5.1 Pipeline Capacity on Canadian Gas Transmission Systems

Figure 5.1 illustrates the Canadian natural gas transmission systems and their annual capacities.[1] Major U.S. systems which interconnect with the Canadian systems are shown as well.

Table 5.1
Pipeline Utilization During
January and February*

	Capacity	Two-month Percent Utilization			
	(PJ)	1986	1987	1988	1989 (Forecast)
Westcoast	95	75	79	78	83
NOVA	450	80	75	92	93
ANG	100	70	93	99	99
Foothills	70	46	34	96	96
TCPL (West)	280	91	80	88	90
TCPL (Central)	120	98	97	99	99

* Data for the TransGas system in Saskatchewan unavailable.

Most major Canadian transmission systems have operated at high levels of capacity utilization during the January-February period of peak winter demand, and this is expected to continue (Table 5.1). The 1988 average utilization of over 90 percent during these months indicates that there were many days when the pipelines operated at or near peak capacity. The situation on the central section of TCPL's system, which serves Ontario and Quebec, is of particular concern.

In the following pages, we review the situation on each of these systems in more detail.

Westcoast - British Columbia

With the exception of part of southeastern British Columbia which receives its gas from Alberta, British Columbia's own gas production serves that province's requirements through the facilities of Westcoast Energy Inc. Westcoast's system has been underutilized due to low rates of take under Westcoast's major export contract with Northwest Pipeline Corporation. Utilization has gradually improved since 1983 (Figure 5.2).

Annual capacity of Westcoast's main line is 550 petajoules. We forecast an annual requirement in 1989 of 410 petajoules, 205 petajoules of which is expected to be exported, indicating a capacity usage of about 75 percent.

Utilization of the export section of the line, which has a capacity of 305 petajoules per year, is forecast to average about 67 percent. As the forecast throughputs are well within

1. The annual pipeline capacities in this report are estimates by Board staff based on information in facilities applications and actual throughput reports filed with the Board. To assess a pipeline's capacity, many factors must be considered, including differences in seasonal and peak day capacities, need for annual maintenance work, etc. The annual capacities shown in this report must be considered as illustrative only.

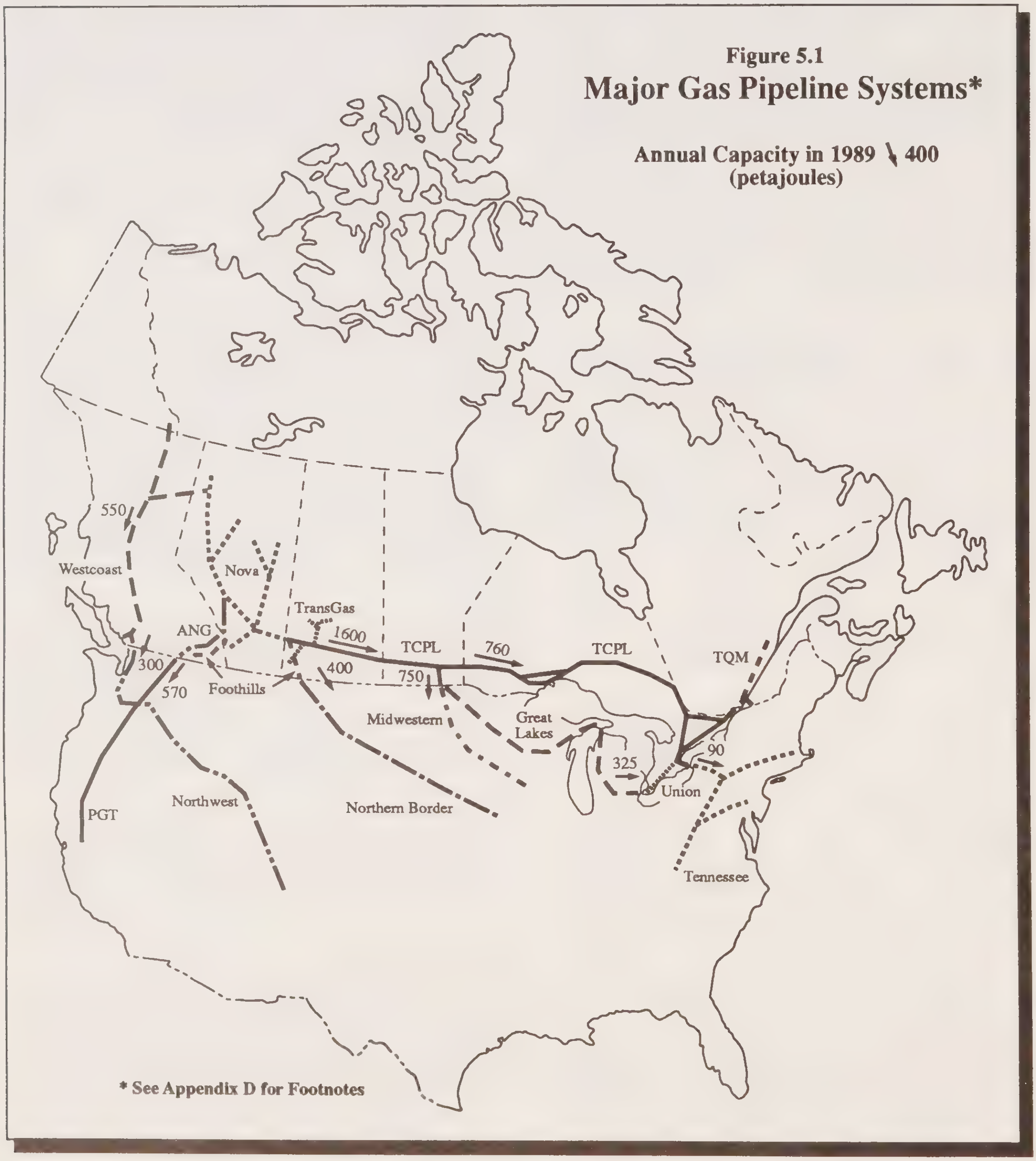


Figure 5.1
Major Gas Pipeline Systems*
Annual Capacity in 1989 400
(petajoules)
550
Westcoast
Nova
TransGas
ANG
1600
TCPL
760
TCPL
TQM
300
570
Foothills
400
750
Midwestern
Great
Lakes
90
325
Union
PGT
Northwest
Northern Border
Tennessee
* See Appendix D for Footnotes

the capability of the system, we foresee no capacity constraints on the Westcoast transmission system in 1989. However, as noted in Section 3.3, during the last two years there have been capacity constraints on the gas processing plants upstream of the transmission system.

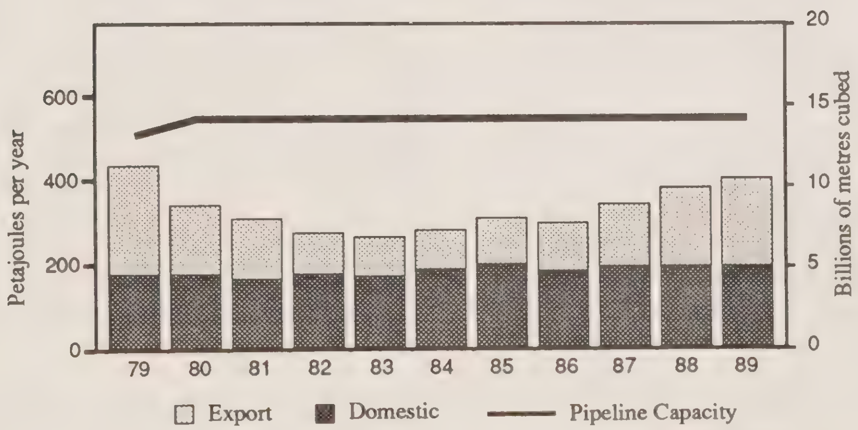
To enhance the ability of producers to maximize sales, Unocal Canada Limited and Westcoast are developing the Aitken Creek oil reservoir in northern B.C. into a gas storage site. This will enable fully-processed gas to be stored in the summer and withdrawn from storage in the winter, permitting higher utilization rates of upstream processing and transmission facilities.

NOVA - Alberta

Alberta's own provincial needs are delivered through the facilities of Northwestern Utilities and Canadian Western Natural Gas, as well as through deliveries directly to end-users off the NOVA system. In addition, through NOVA's facilities, Alberta supplies gas to markets outside the province through the systems of Alberta Natural Gas, Foothills Pipelines and the TCPL system. Small volumes are exported to Montana through the Canadian-Montana Pipeline system.

While no capacity constraints have been identified for intra-Alberta markets, NOVA transported record levels of gas in 1987 and

Figure 5.2
Pipeline Capacity Utilization*
Westcoast



*See Appendix D for footnotes

was forced to curtail some interruptible transportation last winter. NOVA has received many requests for new firm service in the last year and is planning new facilities to accommodate these requests. However, NOVA has notified all shippers on its system that new firm service for any requests not received prior to December 1987 cannot be provided at most receipt points prior to 1 November 1990.

Capacity limitations on NOVA may restrict any further expansion of domestic or export sales of Alberta gas in the near term to off-peak periods, generally the months of March through December.

Alberta Natural Gas and Foothills

Alberta supplies large quantities of gas to the California market through the combined facilities of the Alberta Natural Gas System (ANG) and the western leg of the Foothills system. The export point is at Kingsgate, British Columbia. Total annual capacity on this system is 570 petajoules while the forecast 1989 demand is 520 petajoules, indicating a 91 percent expected utilization rate (Figure 5.3). Additional exports may be possible through this system but will likely be limited to off-peak summer sales.

The eastern leg of the Foothills system transports Alberta gas to the Monchy, Saskatchewan export point where it is exported to the central U.S. region. The line capacity is 400 petajoules per year and forecast export demand is 365 petajoules in 1989, also indicating a 91 percent capacity utilization (Figure 5.3). As with the Kingsgate export facility, additional sales will likely be limited to off-peak months.

TransGas - Saskatchewan

Saskatchewan's own production supplies most of that province's demand, about 90 petajoules per year. About 75 percent of Saskatchewan's gas needs are delivered through the facilities of the TransGas provincial transmission system and about 25 percent is delivered via the TCPL system. The facilities of TransGas are also used to deliver Saskatchewan production to the TCPL system for transmission outside the province. A $93 million expansion of the TransGas system is currently being completed which will increase capacity for ex-Saskatchewan deliveries from about 30 petajoules/year to 100 petajoules/year by December 1988.

TransGas has received requests for additional firm service of about 60 petajoules/year for the 1989/90 gas year and is planning to add new facilities to meet this demand.

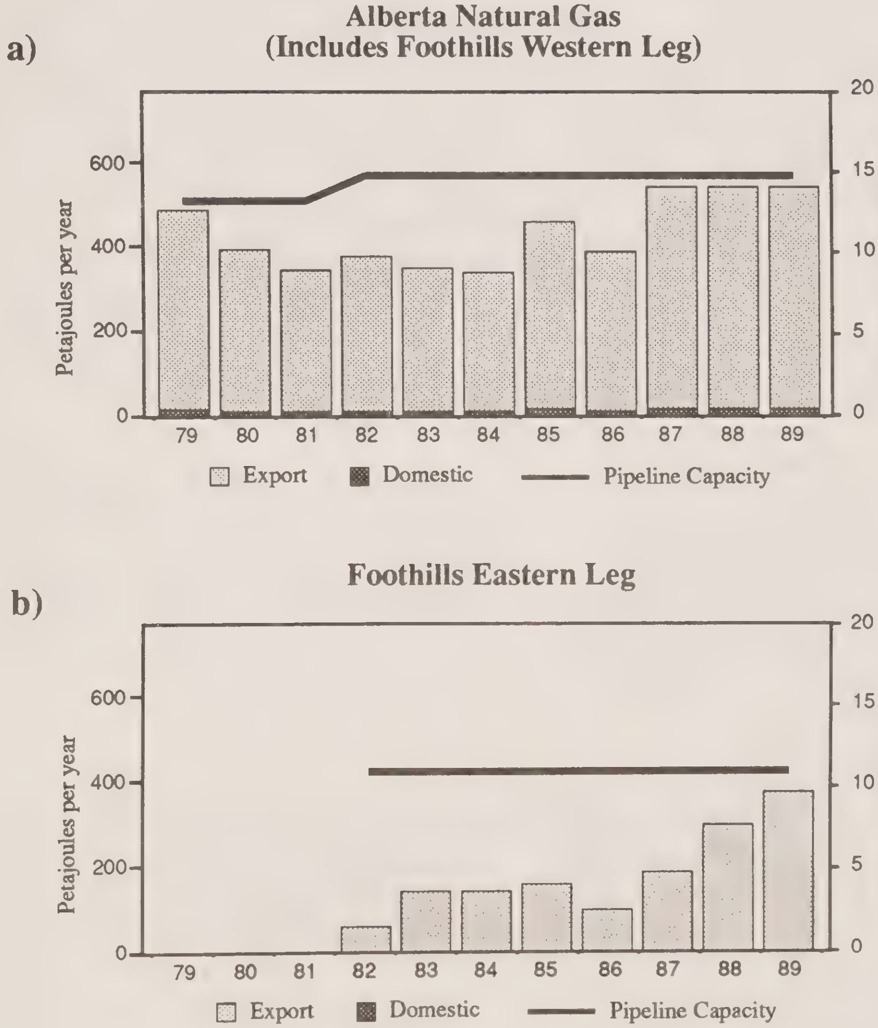
TCPL System

The TCPL system transports Alberta and Saskatchewan gas to domestic markets and export points east of Alberta. Alberta gas supplies essentially all of the market in Manitoba, Ontario and Quebec except for about 20 petajoules/year which is produced and consumed in Ontario. As well, a small amount of gas is imported into Ontario from the U.S. but these volumes have not been considered in this analysis. As previously noted, imports could increase in the near future and have an impact on pipeline utilization and the planning of future capacity on the TCPL system.

The total requirement for Alberta and Saskatchewan gas entering the TCPL system, based on our domestic and export

Figure 5.3

Pipeline Capacity Utilization*



*See Appendix D for fotnotes

demand outlook, is about 1380 petajoules in 1989, of which 325 petajoules is export demand. The capacity of TCPL's western section, which delivers this gas through Saskatchewan and Manitoba, is about 1600 petajoules per year, indicating an expected 86 percent capacity utilization on this segment of the system (Figure 5.4).

The annual capacity of the export line serving the Emerson export point is 750 petajoules, of which TCPL has about 325 petajoules of firm service used for the transshipment of gas to eastern Canadian markets via the Great Lakes Gas Transmission System (Great Lakes) in the U.S. Of the 425 petajoules of remaining export capacity at Emerson, only about one-half is estimated to be required during the 1988/89 gas year, primarily for export sales into the central U.S.

Although not all of the available capacity on Great Lakes is expected to be used in the next two years, most of this capacity is dedicated to various shippers who have contracted for firm service with Great Lakes. As Great Lakes is not an open access system, access is effectively limited to those shippers who have contracted for firm service. Consequently, Great Lakes cannot be relied upon to accommodate potential increased sales to eastern Canada in the near term.

East of Manitoba, the capacity to ship gas to eastern Canada drops to 1085 petajoules per year, 760 petajoules of which is available on the TCPL system running north of Lake Superior, with the remaining 325 petajoules available through the U.S. on Great Lakes. The estimated requirement to deliver gas east of Manitoba in 1989 is about 1070 petajoules, including exports of 115 petajoules, of which about 90 petajoules are expected to flow via Niagara Falls. Therefore, this section of the TCPL system should be fully utilized, leaving little or no opportunity for additional sales unless additional facilities are installed.

TCPL has recently been granted approval to install about $120 million of facilities on its central section. However, TCPL has since revised its forecast of expected throughputs upwards and has modified its system expansion plan. In July 1988 TCPL submitted an application to the Board to spend up to $550 million in order to cope with increased demand and to provide for a margin of advance capability.[1]

In summary, throughputs on TCPL's central section and the Great Lakes system are expected to be at or near capacity during the 1988/89 and 1989/90 winter heating seasons.

Without some further system expansion, capacity limitations will constrain further market expansion in eastern Canada and the U.S. northeast. There should be some unused capacity on TCPL's western section to Emerson, Manitoba which could be used to increase exports to the U.S. mid-west, at least until November 1989.

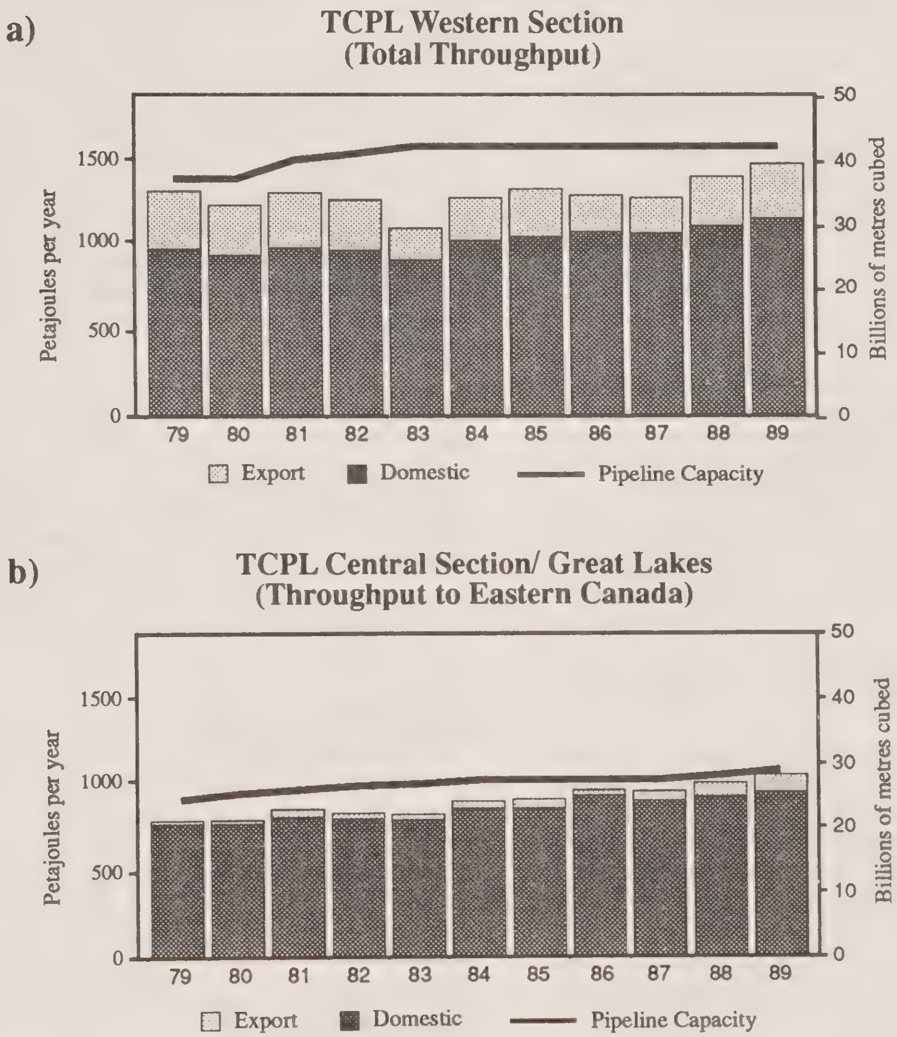
5.2 Storage Capacity

Pipeline transmission facilities and storage facilities are most properly viewed as components of an integrated natural gas delivery system. We estimate peak day end-use demand in eastern Canada to be about 5.5 petajoules/day. This is over twice the average daily load. Extensive storage reservoirs have been developed to minimize the requirement for more expensive transmis-

1. A hearing on this application commenced on 18 October 1988 and the Board's decision is pending.

Figure 5.4

Pipeline Capacity Utilization



*See Appendix D for fotnotes

sion pipeline capacity from Alberta. These reservoirs have a total sendout capacity of about 2.5 petajoules/day and can deliver about 40 percent of winter daily requirements for Ontario and Quebec.

Table 5.2
Canadian Gas Storage Capacity[1]
(petajoules)

	Total Reservoir Capacity[2]	Total Working Capacity[2]
Ontario	240	170 [3]
Saskatchewan	145	33
Alberta	145	32
Total Canada	530	235 [4]

1. Data adapted from Canadian Natural Gas Focus, Volume II, Issue 2, August 1988, p.5.
2. Total reservoir capacity refers to the total amount of gas in the reservoir whereas working capacity refers to the amount of gas available for withdrawal.
3. Of this amount, 107 petajoules (63%) is owned and operated by Union Gas Ltd. and 63 petajoules (37%) is owned and operated by Consumers Gas Ltd. Inter-City Gas Ltd. also owns some liquified natural gas (LNG) storage but these volumes are not included in the above table.
4. LNG storage capacity is excluded from the total because the volumes involved are very small.

Consumers' has the greatest need for storage due to the large percentage of its customer load which is comprised of temperature-sensitive residential and commercial customers. Union, which owns and operates about 63 percent of the existing storage capacity in eastern Canada, provides storage and related gas transmission services to Consumers' and other eastern Canadian distributors.

Gas is injected into storage during the low demand summer months and withdrawn to meet end-users needs during the high demand winter months. This allows TCPL and the local distributors to even out the seasonal swings in demand, thereby helping to maintain a high level of mainline transmission system utilization year round.
TCPL's central section system serving markets east of Manitoba is thus designed for average day requirements throughout the year, and has been operating near capacity for the last two years. TCPL also delivers gas from storage facilities in Ontario to other end-use points in Ontario and Quebec which do not have extensive storage facilities. Therefore, to accommodate peak winter deliveries, pipeline facilities east of the major storage reservoirs in southern Ontario have been designed to transport gas at peak day levels.

The introduction of direct sales has heightened interest in storage services. Whereas load-balancing and back-stopping were previously solely the responsibility of the distributor, an end-user purchasing gas directly from a producer may now wish to separately contract for these services. Union, for example, now offers an unbundled storage service to end-users.

Consumers' and Union have recently received approval from the Ontario Energy Board to jointly develop an additional 17 petajoules of storage capacity at the Dowmoore pool. This facility is expected to be in service by 1 November 1989. The Dowmoore pool is the last known reservoir in southern Ontario suitable for gas storage. Eastern Canadian utilities may eventually have to contract with distributors in the U.S. if further access to storage is required.

In addition to the use of storage, distributors have further flexibility to meet peak day

requirements by reducing deliveries to some of their customers, normally large industrial users who have dual fuel capability and who purchase gas under interruptible contracts.

5.3 Assessment of Available Pipeline and Storage Capacity

All major transmission systems transporting gas within Canada and to export destinations, with the exception of Westcoast, are currently operating at or near capacity. In particular, both the NOVA transmission system in Alberta and the central section of the TCPL system will likely be operating at capacity on peak days during the coming two winter heating seasons.

In past years, a number of shippers have relied on interruptible service for a portion of their firm requirements because interruptions were quite rare and cost savings could be obtained by using interruptible instead of firm service. However, it is likely that the frequency of interruption will increase greatly during the next two winters.

Although gas demand is not anticipated to increase rapidly in eastern Canada in the near term, exports to the U.S. northeast and mid-west are forecast to increase substantially.

The combination of more frequent interruptions of interruptible service and growing export demand has induced gas shippers to request additional firm service from NOVA, TransGas and TCPL which will require construction of new facilities. Given the time required for pipeline planning, regulatory approval and construction, new facilities can only be provided with a lag, which may be as long as two years after the request for service is made.

Similarly, although Union and Consumers are developing additional storage capacity, it will not be available to help alleviate any peak day deliverability problems that may develop this coming winter.

The lack of spare capacity on TCPL's central section, combined with the lack of access to Great Lakes, will constrain TCPL's ability to increase gas deliveries to eastern Canada in the near term. If this coming winter were to prove to be colder than average, TCPL would likely have to cut service to interruptible customers on peak demand days. Of course, this does not imply that deliveries to any end-users relying on firm service will be affected. Most consumers relying on interruptible service are industrial gas users who have the option of switching to either fuel oil or electricity if their gas supply is interrupted.

The lack of spare capacity on NOVA will also constrain near term growth of exports of Alberta gas to the U.S. mid-west and northeast. Some additional exports could be made, for example, from Saskatchewan to the U.S. mid-west from Emerson via the Mid-Western pipeline in the 1989/90 gas year.

In summary, the combined delivery capability of the gas transmission and storage systems should be sufficient to satisfy all firm service under existing contracts to eastern Canada during the next two winter heating seasons. However, interruptible service will likely be interrupted on NOVA and TCPL with increasing frequency. Further, ***the tight pipeline capacity situation will limit opportunities for expanded export sales to most U.S. markets in the near term.***

Chapter 6

Conclusions

Our review of recent developments in the Canadian natural gas market indicates that major changes have occurred since the implementation of the 1985 Natural Gas Agreement. Prior to the Agreement, the interprovincial market was characterized by a small number of shippers (of which TCPL was by far the largest) selling to a small number of local distribution companies. In the past two years the number of gas producers selling directly to end-users has increased dramatically. This has generated strong competition between sellers and, given the large excess of productive capacity that has overhung the market, wellhead prices have declined steeply.

Producers have been quick to respond to the challenges of marketing gas in the new competitive environment. For example, since the introduction of direct sales, Saskatchewan producers have been very successful in both developing and marketing new reserves. The rapidity with which a major expansion of the TransGas transmission system in Saskatchewan was conceived, approved and built further testifies to the ability of the producing sector to respond to new market opportunities.

Producers have also been quick to develop marketing expertise and penetrate new markets. For example, exports under short term orders increased from 18 petajoules to 147 petajoules between 1986 and 1987. As well, whereas gas purchases in eastern Canada were only made by a handful of distribution companies in 1985, purchases are now being made by some 460 companies and institutions.

For their part, gas consumers have rapidly taken advantage of the opportunities offered by direct sales. This is witnessed by the efforts of groups such as school boards,municipal collectives, and hospitals to obtain lower priced gas through direct purchases from producers. Where, as in the case of Saskatchewan, producer governments have not stood in the way of such arrangements, useful cost savings have resulted for end-users. The emergence of brokerage firms has also facilitated sales between producers and end-users.

While producers have looked across the border for new markets, buyers have also looked south for new sources of gas supply. Attempts to increase ties between Canadian and U.S. markets reflect efforts by buyers to diversify their sources of supply.

Governments and regulatory agencies in Manitoba, Ontario and Quebec have taken steps to accommodate direct sales. However, the terms and conditions of access to the distribution systems are still subject to close regulatory oversight.

In short, as envisaged by the 1985 Gas Agreement, the market has demonstrated increasing flexibility to respond to changing market circumstances. Producers now have a wider range of market opportunities while end-users can choose from a wider variety of supply options.

Notwithstanding the substantial increase in market flexibility, some impediments to fully competitive pricing remain.

In the last few years, something of a dichotomy has been created in the Canadian natural gas industry. On the one hand, TCPL/WGML, the TOPGAS consortia, the major system gas producers and the Alberta government have been attempting to maintain the market share of system gas. On the other hand, producers holding substantial uncontracted reserves, gas marketing firms

and many consuming interests support the continued rapid development of the direct sales market.

The outcome of these market circumstances can be seen from the data on direct sales. High volume industrial customers have received substantial price reductions in the past two years. However, prices to other end-users have not fallen to the extent that they would if these end-users were free to negotiate prices directly with producers. The fact that end-users such as hospitals and educational institutions have been able to obtain large price reductions by purchasing gas directly from Saskatchewan producers supports this conclusion. Thus, although full competition has arrived in the industrial sector of the market, the commercial and residential sectors have not yet benefitted to the same extent from competitive pricing.

The transition from fully regulated prices to a competitive pricing environment was never anticipated to be easy. The steep fall in energy prices which followed the signing of the 1985 Gas Agreement exacerbated the difficulties of the transition for gas producers and for the province of Alberta. Given the impact on producer revenues and Alberta government royalties, it is understandable that there has been some attempt to support domestic prices for gas sold under long term contracts.

Short-Term Supply/Demand Balance

The excess productive capability which has recently characterized the Canadian gas market is declining, largely as a result of low gas prices which have discouraged exploration.

Our expectation is that the excess will decline further in the next two years. Nonetheless, annual productive capacity is expected to remain considerably in excess of annual demand. There is a much smaller excess of daily productive capacity over peak day demand. Projected growth in exports suggests that this relationship will get tighter in the next two years.

Pricing Outlook

Given the excess supply situation, prices to domestic industrial users are expected to increase very little if at all over the next two years.

Average prices of sales of Canadian gas into domestic markets and U.S. markets have been similar throughout most of 1988. Export prices should not, on average, diverge appreciably from domestic prices at the Alberta border. However, U.S. spot prices have exhibited considerable volatility and it is possible that prices for short term exports will fall below domestic prices for comparable service from time to time.

Wholesale prices of gas sold to most eastern Canadian residential and institutional customers have effectively been set at $2.20/GJ at the Alberta border for the next two years as a result of the recent agreements between WGML and the major distribution companies.

Pipeline and Storage Capacity

All major transmission systems transporting gas within Canada and to export destinations, with the exception of Westcoast, are currently operating at or near capacity. In particular, the NOVA system in Alberta and the central section of the TCPL system are expected to operate near capacity during the next two winter heating seasons. Thus, there

will be little scope for increased sales to eastern Canada or the northeast U.S. in the near term.

The winter of 1987/88 was exceptionally warm and residential demand was almost 10 percent below normal. If the winter of 1988/89 were to be much colder, residential demand would be much higher than last year. Industrial demand is also forecast to increase in the coming year. In these circumstances, it is likely that interruptible service will be cut off more frequently than in the past because gas flowing under firm service contracts would use most or all available capacity on NOVA and TCPL's central section.

A decrease in the ability to rely on interruptible service, combined with growing export demand, has resulted in new requests for firm service on NOVA, TransGas and TCPL. However, due to system planning and regulatory lags, many shippers will have to wait for up to two years before their requests can be satisfied.

Summary

In summary, our assessment indicates that the market has been adequately supplying Canadian gas needs. The evidence on domestic prices versus export prices indicates that, on average, Canadians are obtaining gas at prices generally no greater than those paid by export customers. Although there are a number of outstanding issues to be resolved regarding pricing and supply arrangements for so-called core market users, a degree of flexibility exists in the market today which, to many, was unthinkable just a few short years ago.

Regulation of the Canadian Natural Gas Industry

Though gas prices are no longer set directly by governments, there remain elements of regulation in all segments of the Canadian gas industry. This appendix provides a brief review of producer province regulation over the production and sale of natural gas, of federal regulation over interprovincial and international gas transportation, of provincial government regulation over the distribution of natural gas and, finally, of federal licensing of natural gas imports and exports. By way of introduction, Figure A.1 provides a brief breakdown of the current status of regulation of the natural gas industry in Canada.

Producer Province Regulation over the Production and Sale of Natural Gas

Section 92(a) of the *Constitution Act, 1867* gives each province the exclusive right to make laws in relation to the development, conservation and management of natural gas in the province. The provinces also have the right to make laws in relation to the sale of a province's natural gas to another part of Canada, provided that such laws do not provide for discrimination in prices or in supplies.

All three producer provinces require shippers or producers to obtain provincial approval before gas is allowed to be removed from the province. In Alberta, the *Gas Resources Preservation Act* empowers the provincial government to deny approval of a gas removal permit in cases in which the terms and conditions of sale, including price, would not be in the best interests of the province. One condition of ministerial consent is that a sale to a distributor must not displace Alberta gas that would be sold under existing sales contracts.[1]

In British Columbia, the Minister of Energy, Mines and Petroleum Resources has the authority to issue energy removal certificates under the *Utilities Commission Act.* Among other conditions, removal certificates for B.C. gas generally require that the gas not be sold to out-of-province customers for less than the price charged for similar types of service in the market area in British Columbia adjacent to the export point.

In Saskatchewan, gas removal permits are issued by the Ministry of Energy and Mines. Unlike in Alberta and B.C., the gas removal permits are issued to producers, not shippers. The producer must demonstrate that it has sufficient deliverability capability to meet its contractual obligations. Saskatchewan's gas removal permitting process also stipulates that prices for gas leaving the province must not be lower than those paid by provincial customers for similar types of sales and removal permits will not be issued for sales which displace Saskatchewan sales presently under contract.

All three provinces also provide some protection for the long term gas needs of provincial "core-market" gas users. In March 1987, the Alberta Energy Resources Conservation Board (AERCB) relaxed its gas export surplus test from its previous 25 years protection of the total Alberta market to a surplus test designed to protect 15 years of core market requirements. Core market requirements were defined to be the sum of residential,

1. For a further discussion of Alberta's gas removal permitting policy, see pages 17-18.

Figure A.1

CURRENT STATUS OF REGULATION OF THE CANADIAN NATURAL GAS INDUSTRY

JURISDICTION	ACTIVITY	REGULATION STATUS
Producing Provinces	Production	Royalties, regulation for conservation
	Gathering & Processing	Facilities approval (safety and environmental considerations)
	Intra-provincial Transmission	Regulation on a complaint basis.
	Extra-provincial Sales	Removal permits and certificates
Federal	Interprovincial & International Transmission	Facilities approval, tolls and tariffs
	Exports & Imports	Licences and orders
Consuming Provinces	Gas Distribution	Tolls and tariffs, facilities approval, licensing of LDCs and brokers
	End-User	By-pass issue (currently before the courts)
	Gas Purchase Contracts	Monitoring/approval of terms and conditions

commercial and small industrial requirements.

In July 1987, the British Columbia government adopted a procedure similar to Alberta's.

In October 1987, the Saskatchewan government removed volume limitations on exports from the province but required the SPC (now Provincial Gas Ltd.) to maintain a 15-year reserve to meet provincial needs. This will be accomplished through contracts negotiated between Provincial Gas Ltd. and Saskatchewan producers.

The provincial governments in the producing provinces also regulate the production of natural gas to ensure that sound conservation practices are followed. In Alberta the AERCB sets maximum daily production limits for all producing gas wells. In British Columbia, this role is fulfilled by the Department of Energy, Mines and Petroleum Resources and in Saskatchewan by the Department of Energy and Mines.

The AERCB is responsible for approving construction of new gas gathering, processing and transmission facilities in Alberta while the Department of Energy and Mines fulfills this role in Saskatchewan. In British Columbia, however, gathering and processing facilities are an integral part of the Westcoast system and any new facilities construction must be approved by the NEB. In all cases, an applicant must satisfy the regulatory authority with regard to the need for any new facilities and the cost-effectiveness of the design, and must satisfactorily address any safety, environmental or other public interest concerns.

The charges for gathering and transmission on the NOVA system in Alberta are set by NOVA and are subject to review on a complaint basis by the Alberta Public Utilities Board (PUB). NOVA's rates for gas transportation to the Alberta border are set on a "postage stamp" basis and all shippers pay the same rate regardless of the geographical location of the gas fields from which they draw their supply.

Gas transportation rates on Westcoast's system in British Columbia are regulated by the NEB. Gas transportation rates on the TransGas system in Saskatchewan are currently set by TransGas although the provincial government may implement a public review process in the future.

Finally, all three provinces also collect royalties on gas production and, although the details vary, the royalties are essentially a percentage of the wellhead price received by the producer.[1]

Federal Regulation of Interprovincial and International Gas Transportation

The NEB Act gives the Board two primary responsibilities with respect to domestic gas transportation:

(i) regulation of tolls and tariffs on interprovincial and international gas pipelines; and

(ii) regulation of the construction and operation of interprovincial and international gas pipeline facilities.[2]

---

1. For a further discussion of Alberta's royalty system, see page 18.
2. An international gas pipeline is a pipeline which crosses the border between Canada and the United States. The Board has jurisdiction over the domestic portion of such pipelines.

For the purposes of toll and tariff regulation the Board has divided the companies that operate gas pipelines under its jurisdiction into two classes. Class one companies are audited by the Board on a regular basis and changes to their tolls generally require a public hearing.[1] Tolls of class two companies are regulated on a complaints basis.

The issues addressed at toll hearings can generally be divided into three components: tariff matters (including the terms of access), toll design issues and cost of service matters. With the introduction of direct sales into the Canadian natural gas market, the terms and conditions of access have become of critical importance to gas shippers and, hence, these issues have demanded considerable attention at recent toll hearings.[2] Toll design issues include issues about the types of services that will be offered and the respective charges for these services.

Cost of service matters consist of an inquiry into a pipeline's total cost of service. Based on the evidence presented, the Board makes a determination of the pipeline's total allowable costs and determines a target for the company's annual rate of return on its regulated activities.

Part III of the NEB Act charges the Board with the responsibility of approving the construction and operation of proposed new pipeline facilities. The Board normally approves minor additions or modifications to existing pipeline systems (installations such as tanks, pumps, compressors and meter stations, and pipeline segments less than 40 kilometres in length) without a public hearing. Consideration of major new facilities requires that the Board hold a public hearing.

Public hearings on proposed new pipeline facilities may address a broad range of issues. The applicant must normally demonstrate that there is a need for the new facilities, that the design chosen is appropriate to attain the desired objectives and that the cost is reasonable. In addition, the applicant must demonstrate that it will satisfactorily address safety and environmental concerns that either the Board or any intervenors may have with respect to the proposed facilities. Finally, the applicant must demonstrate that it will satisfactorily address socio-economic concerns and any other public interest issues raised by the application.

If the Board finds that all of the above concerns are satisfactorily addressed by the applicant, the Board may issue a certificate approving the facilities, subject to Governor in Council approval. The Board may then hold a detailed route hearing which provides persons whose lands may be affected with an opportunity to present their views to the Board before a final detailed route is approved.

The Board is also responsible for ensuring that pipelines are operated in accordance with the public interest. To ensure safe and efficient pipeline operations, the Board carries out inspection programs and conducts

1. Currently, only four gas pipeline companies are actively considered to be class one companies. These are Foothills Pipe Lines (Yukon) Ltd. (Foothills), Trans Quebec & Maritimes Pipeline Inc. (TQM), TransCanada PipeLines Limited (TCPL) and Westcoast Energy Inc. (Westcoast). Although Alberta Natural Gas Company Ltd. is considered to be a class one company, its tolls are currently regulated on a complaints basis.
2. For a further discussion of some of the Board's recent decisions with respect to the terms of access to TCPL, see pages 22-24.

investigations of pipeline system performance. In addition, the Board audits pipelines' operating and maintenance procedures to ensure that appropriate steps are being taken to ensure adequate environmental protection on an ongoing basis. Finally, the Board may monitor any socio-economic action plans to which a pipeline company may have committed itself at the time the Board approved the construction of new facilities.

Provincial Government Regulation of the Distribution of Natural Gas

Provincial governments, including governments of the producing provinces, regulate the distribution and sale of natural gas within their jurisdiction. Each province has created its own mechanisms for regulation but, in most cases, regulation is effected through a quasi-judicial regulatory board. The primary regulatory activities are similar to the regulatory responsibilities of the NEB with respect to interprovincial and international pipelines in that the provinces approve the rates charged to end-users by the local distribution companies and regulate the construction and operation of gas facilities under their jurisdiction. In addition, the provinces are responsible for granting franchises to local distribution companies and for licensing gas brokers.

The issues addressed at public hearings into rates charged by local distribution companies can generally be divided into four components: tariff matters, toll design issues, cost of service matters (including the approval of gas purchase costs), and the allocation of costs to different customer classes.

Tariff matters include the terms and conditions of access. Since the introduction of direct sales in interprovincial markets, all gas consuming provinces have implemented legislation requiring distributors to carry gas for third parties. However, the specific terms under which access must be provided are not uniform accross the provinces.

Toll design issues include questions such as whether separate rates should be charged for storage, load-balancing and back-stopping services provided to end-users by distributors or whether these charges should be "bundled" together into one rate.

Cost of service issues have recently focussed upon approval of distributors' gas purchase costs. Prior to 1 November 1985, prices for interprovincially traded gas were regulated and distributors had little flexibility in adopting gas purchase strategies. Since the implementation of the 1985 Gas Agreement, distributors have been free to negotiate prices with producers for all incremental purchases of gas and for volumes under their long term sales contracts. However, distributors have argued that they have not been able to displace their existing sales obligations to WGML with other sources of supply (see discussion on pages 23-24).

The allocation of a distribution company's costs to different customer classes is often an issue at provincial rate hearings because this allocation determines the relative rates to be charged to industrial, commercial and residential end-users. In Ontario, there has recently been some re-allocation of distributors' gas distribution costs away from the industrial class to the commercial and residential classes. This was done to remove previous cross-subsidization of commercial and residential end-users by industrial end-users. More significantly, as a result of negotiations over gas prices for volumes under long term sales contracts, gas purchase costs have recently fallen more rapidly for the

industrial class than for either the commercial or residential classes. Hence, approval of gas purchase costs and the allocation of these costs has become a controversial issue at provincial rate hearings.[1]

In the context of facilities jurisdiction, the provinces have implemented approval processes which essentially parallel those of the NEB at the national level. Distribution companies wishing to construct new facilities must satisfy the regulatory agency as to the need for such facilities and the cost and suitability of the design, and must satisfactorily address any safety and environmental concerns.[2]

Federal Licensing of Natural Gas Imports and Exports

The Board authorizes licences and orders for imports of natural gas. To date, all applications for such authorization have been uncontroversial and have been issued without a public hearing.

The NEB's procedures for licensing long term volumes of exports from Canada are described in the introduction. Applications for exports for a term of less than two years are approved via the issuance of a Board order and do not require a public hearing.

Federal policy with respect to natural gas export prices has varied over the years. Prior to 1975, export prices were freely negotiated between buyers and sellers, although they were subject to approval by the NEB. From 1975 to 1984, export prices were set directly by the federal government. In November 1984, the federal government revised its export pricing policy to allow gas exports at negotiated prices subject to certain criteria, the key one being that the export price was not to be less than the wholesale price of natural gas at the Toronto city gate for gas sold under similar terms and conditions.[3]

Until 31 October 1986, the Board was responsible for granting prior approval of the price provisions in gas export contracts. However, the signatory parties to the 1985 Gas Agreement recognized that in a market-oriented regime prices must be free to vary according to market conditions and that, with many buyers and sellers, a multitude of prices is likely to exist at any point in time. They agreed that prior approval of export prices would be incompatible with such a market environment and, as of 1 November 1986, the Board's approval process was replaced by an after-the-fact monitoring process administered by a joint federal/provincial committee.[4]

---

1. Recent provincial decisions on toll and tariff issues are discussed on pages 24-29.
2. An interesting issue that has arisen since the implementation of the Agreement on Natural Gas Markets and Prices is the question of whether or not end-users should be allowed to construct facilities which would connect them directly to TCPL, thereby allowing them to "bypass" the local distribution company.
3. In October 1985 the Toronto floor price was replaced with a system of regional floor prices.
4. For a review of the recent reports of this committee, see pages 31-34.

Major U.S. Pipelines Directly Connected to Canadian Pipelines

Company	Open Access	% Share of Can. Exports[1]
PGT	No	42
Northern Border	Yes	25
Great Lakes	No	13
Northwest	Yes	11
Midwestern	No	5
Tennessee	Yes	3
Montana Power	No	1
Panhandle Eastern PipeLine Co.	Yes	*

Major U.S. Pipelines Indirectly Connected To Canadian Pipelines

Company	Open Access	% Share[2]
Natural Gas Pipeline of America	Yes	6
ANR Pipeline Co.	Yes	5
Texas Eastern Trans. Corp.	No	4
Transcontinental Gas Pipe Line	Yes	4
Northern Natural Gas Co.	Yes	4
Texas Gas Transmission Corp.	Yes	4
El Paso Natural Gas	No	4
Southern California Gas	No	3
Columbia Gas Trans.	Yes	3
United Gas Pipeline Company	Yes	2
Trunkline Gas Co.	Yes	2
Colorado Interstate Gas Co.	Yes	2
Southern Natural Gas Co.	Yes	1
Transwestern Pipeline Co.	Yes	1
Williams Natural Gas Co.	Yes	1
Consolidated Gas	Yes	1

* Less than 1 percent
1 Based on volume throughput from 1 Nov. 1987 to 31 August 1988.
2 Ranking based on volume of total gas transported in 1987.

Apppendix C

Glossary of Terms and Definitions

Back-Stopping	A service whereby backup supplies are provided in the event that a customer's gas fails to be delivered to the distributor.
Beyond Economic Reach Reserves	Established reserves, which because of size, location or composition are not considered economically viable at the present time.
Broker	A gas broker is an entity other than an LDC that brings together buyers and sellers of gas and may or may not take title to the gas. Thus the broker acts as an agent or consultant.
Commodity Charge	A commodity charge is a charge payable by a gas purchaser in a sales contract for each unit of gas purchased. The unit charge generally covers the commodity component of the applicable pipeline toll and the cost of gas, and may include a portion of the fixed costs of the seller.
Bundled Rate	A single charge that covers a number of services provided by a pipeline or distributor. Examples of such services are gas sales, transportation, storage and load-balancing.
Buy/Sell	In this arrangement, the end-user purchases its own supply of gas and arranges for transportation, generally to the distributor's delivery point. The distributor purchases the gas and commingles it with the balance of its supplies, and then sells gas to the end-user as a sales customer under the appropriate rate schedule.
Bypass	Bypass involves the total avoidance of the LDC's system for the transportation of gas.
Competitive Marketing Program (CMP)	A mechanism by which WGLM has provided specific discounts to individual end-users of gas. Generally the distributor sells to the end-user under the approved sales rate schedule. The distributor advises the pipeline of volumes sold each month. The pipeline rebates to the distributor the agreed upon discount for the preceding month's volumes and the distributor flows the rebate through to the end-user. (WGML replaced CMPs with SGRs on: January 1988.)

Consuming Provinces	Those provinces of Canada which consume more natural gas than they produce - Manitoba, Ontario and Quebec.
Core Market	Generally that part of the gas market that does not possess fuel switching capability; typically, residential, commercial and small industrial users.
Demand Charge	A demand charge is a fixed, usually monthly obligation of a gas purchaser in a sales contract. It may cover some or all of a seller's fixed costs and is payable regardless of volumes actually taken.
Direct Sale or Direct Purchase	Natural gas supply purchase arrangements transacted directly between producers or brokers and end-users at negotiated prices.
Displacement Volume	A direct purchase volume is a displacement volume when, assuming the absence of such direct purchase, the LDC could supply the account on a firm contract basis without itself contracting for additional firm volumes to accommodate the demand.
Economic Regulatory Administration U.S. (ERA)	The ERA, under the direction of the Secretary of Energy, is responsible for approving exports and imports of gas from and into the U.S.
Established Reserves	Those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing or production, plus that judgment portion of contiguous recoverable reserves that is interpreted to exist, from geological, geophysical or similar information, with reasonable certainty.
Federal Energy Regulatory Commission (FERC)	The FERC is responsible for the regulation of all inter-state trade in gas in the U.S. It regulates the tolls and tariffs of interstate pipelines, approves the construction of new facilities and administers prices for some U.S. gas which is still subject to price controls.
Firm Service	A relatively higher priced service for a continuous supply of gas, without curtailment except under extraordinary circumstances.
Fuel Switching Capability	A customer's ability to use two fuels.

Heavy Fuel Oil	In this report the term heavy fuel oil is used to include bunker fuel oils (No. 5 and No. 6 fuel oils) and industrial fuel oil (No. 4 fuel oil).
Infill Drilling	The process of drilling additional wells within the defined pool outline of a natural gas or oil pool.
Initial Established Reserves	Established reserves prior to the deduction of any production.
Interruptible Customer	A customer whose gas service is subject to curtailment for either capacity and/or supply reasons, at the option of the pipeline company or LDC.
Interruptible T-Service	An interruptible gas transportation service provided under contract for gas which is not owned by the pipeline company. The interruption is at the option of the pipeline company or distributor.
Load Balancing	The balancing of gas supply to meet demand by using storage and other peak supply sources, curtailment of interruptible sales, and diversions from one delivery point to another.
LDC	A local distribution company.
Load Factor	The ratio of the average load over a designated period of time to the contracted maximum load, expressed in percent.
Non-System Producers	Gas producers other than those contracted to supply a pipeline.
Open Access	The non-discriminatory access to transportation services.
Operating Demand Volumes	Volumes specified in a distributor's CD contracts with a pipeline less the volumes deemed to have been displaced by direct sales, as determined under the NEB's rules established for defining displacement volumes.
Peak Demand	The maximum amount of gas required by a customer or LDC over a short period of time (typically one day).

Producing Provinces	Those provinces of Canada which annually produce more natural gas than they consume - British Columbia, Alberta, and Saskatchewan.
Productive Capacity	The estimated rate at which natural gas can be produced from a well, pool or other entity, unrestricted by demand, having regard to reservoir characteristics, economic considerations, regulatory limitations, the feasibility of infill drilling and/or additional production facilities, the existence of gathering, processing and transmission facilities, and potential losses due to mechanical breakdown.
Remaining Established Reserves	Initial established reserves less cumulative production.
Reprocessing Shrinkage	That quantity of natural gas removed from main gas transmission systems at straddle plants and coverted to NGL, expressed in either volume or energy units.
Reserves Additions	Incremental changes to established reserves resulting from the discovery of new pools and reserves appreciation.
Reserves To Production Ratio	Remaining reserves divided by annual production.
Self-Displacement	The purchase of gas by an LDC to displace gas it would otherwise obtain under its contracts with TCPL.
System Gas Resales (SGRs)	A form of buy/sell arrangement wherein the end-user purchases gas from WGML immediately east of the Alberta Border at a discounted price, then resells the gas to TCPL at the Alberta border at the average cost of gas to the distributor. The distributor then sells the gas to the end-users under its normal rate schedule.
System Gas Sales	Gas sold by pipeline companies or their affiliates, eg. WGML's sales.
Take-or-Pay Provision	A clause or provision in a contract requiring that gas contracted for, but not taken, will be paid for.
Unbundled Rate	A rate for an individual, separate service offered by a pipeline or distributor.

Apppendix D

Additional Footnotes to Figures

Figure 2.4 Combined Canada and United States Productive Capacity vs Demand

1. The figure shows total U.S. and Canadian gas productive capacity and consumption on an annual basis.

2. U.S. productive capacity is based on estimates in "Planning and Analysis, Issues", American Gas Association (AGA), 13 July 1987. Canadian productive capacity is based on estimates by Board staff. Total productive capacity is the sum of the estimates for Canada and the U.S. As there are differences in the way in which the Board and the AGA estimate productive capacity, the joint total must be considered to be an approximation only.

3. Demand is based on actual gas consumption.

Figure 3.1 "Alberta Field Prices"

1. Data adapted from "Canadian Natural Gas Focus", Volume 2, Issue 3, September 1988; published by Brent Friedenberg Associates Ltd., Calgary, Alberta; Table 1, page 11.

2. The data represent average monthly field prices paid to system producers by WGML before deduction of any applicable TOPGAS charges. Although some of WGML's sales are exports, most are domestic sales and hence the data are representative of system gas sales in interprovincial markets.

3. The data on direct sales prices are based on a survey of direct shippers. The prices are indicative of prices in firm short term direct sales contracts in intra-Alberta and interprovincial markets.

Figure 3.3 "Domestic and Export Prices - Alberta Border"

1. Data based on "Natural Gas Price Monitoring Report"; Reports No. 1, No. 2, and No. 3, published by the Minister of Energy, Mines and Resources Canada. All data are based on volume-weighted monthly average prices.

2. Firm sales refer to long term sales typically under 15-year sales contracts.

3. Interruptible sales refer to gas flowing under interruptible service contracts and for which the gas price is usually determined on a monthly spot market basis.

Figure 3.4 "Domestic and Export Prices - B.C. Border"

1. Data based on "Natural Gas Price Monitoring Report", Reports No. 1, No. 2, and No. 3, published by the Minister of Energy, Mines and Resources Canada. All data are based on volume-weighted monthly average prices.

2. Interruptible sales refer to gas flowing under interruptible service contracts and for which the gas price is usually determined on a monthly spot market basis.

Figure 5.1 "Major Gas Pipeline Systems"

1. Annual pipeline capacities are estimates by Board staff based on information in facilities applications and throughput reports filed with the Board. To assess a pipeline's capacity, many factors must be considered, including differences in seasonal and peak day capacities. The annual capacities shown must be considered as illustrative only.

Figures 5.2, 5.3, and 5.4 "Pipeline Capacity Utilization" (Same footnotes for each graph)

1. Pipeline capacity utilization is based on annual averages. However, throughputs vary greatly by month and the annual averages shown in the figures mask the fact that the pipeline is being used at or near full capacity during the winter peak months.

2. Pipeline capacities are based on estimates by Board staff.

3. Throughputs for the years 1979-1987 are actuals. The throughputs shown for 1988 and 1989 are estimates by Board staff.

Canada